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Use of hydrogen in the civil sector.

TECHNICAL-ECONOMIC FEASIBILITY STUDY AND APPLICATIONS

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Abstract

The energy needs of buildings account for 40 per cent of the total energy demand in the European context and are to date mainly met by traditional technologies using fossil fuels. In order to complete projects to reduce climate-altering emissions, Europe imposes increasingly stringent constraints on new buildings or those subject to major renovation, but at the same time it is necessary to upgrade the existing building stock in order to achieve the targets necessary to keep the global temperature below the 1.5 °C increase compared to 1990.

This paper investigates the use in the civil sector of hydrogen as a new sustainable energy vector, analysing the ways in which it can contribute to the decarbonisation of energy supply, in line with the predictions formulated by IRENA. A techno-economic feasibility analysis is conducted on a case study of a condominium-sized residential consumer, exploring the possibility of meeting its electricity and heating needs with hydrogen. The system options investigated see the use of a fuel cell as an electric and thermal generator, operating in different modes, and a hybrid boiler as a thermal generator capable of burning a mixture of hydrogen and natural gas.

In order to highlight the factors most influencing the mass deployment of hydrogen in the civil sector, a sensitivity analysis is then conducted on a number of technical-economic parameters of interest.

Parallel to the study outlined above, the aim of this research is to create a design tool useful for dimensioning and simulating a system based on these hydrogen generators by receiving the loads and characteristics of the consumers as input data.

The economic analysis of the case study shows that under current cost and infrastructure conditions, hydrogen is not yet a mature solution for energy production in the civil context. The sensitivity analyses conducted show which aspects need to be improved in order to enable a mass diffusion of this new sustainable resource.

Summary

1 Introduction

1.1 Hydrogen in decarbonisation targets

The current European decarbonisation targets set by the Green Deal aim to reduce greenhouse gas emissions by 55% below 1990 levels by 2030 and to achieve climate neutrality (zero emissions) by 2050[1]. In order to achieve these goals, it is necessary to redevelop all sectors that meet their needs with fossil fuels, including the building sector, which accounts for about 40 per cent of total energy consumption in Europe. According to IRENA [2], widespread energy efficiency, electrification of final consumption and use of renewables can help achieve up to 70 per cent of the decarbonisation targets. Also IRENA quantifies that the necessary use of hydrogen, especially in sectors where no mature and cost-effective alternative solutions are available, can contribute 10% of the emission reduction needed to achieve the 1.5 °C temperature increase scenario compared to 1990 and 12% of final energy demand.

The decision to use hydrogen is motivated by a number of its properties: it is light, can be stored more efficiently in the long term than electricity, has a high specific energy and can be produced on an industrial scale. Moreover, the combustion of hydrogen does not lead to the direct production of climate-changing gases such as CO_2, as it is a carbon-free molecule. Its use is not limited to combustion: it can also participate in electrochemical processes to produce electricity and heat without producing nitrogen oxides with higher efficiencies than those obtained through traditional combustion in devices called fuel cells, the operation of which is discussed in more detail in a later chapter.

The European strategy envisages increasing the use of hydrogen, currently a source of 2% of consumed energy, to 13-14% by 2050, allocating most of the investment to increase the production of sustainably produced European hydrogen [3].

1.2 Hydrogen production

Hydrogen is now produced on a commercial scale and is commonly used as a raw material in the chemical industry and refineries, in steel production, and to a lesser extent in heat and power generation processes. Current global production reaches 75 million tonnes per year for pure hydrogen, plus a further 45 million tonnes in mixtures with other gases, accounting for 3% of final energy demand [2]. Hydrogen can be produced through a variety of processes, according to which the resource is given a different designation, based on a colour. The information below comes mainly from [4], by Della Pietra et Al., who provide an appropriate overview of some salient aspects of production.

Almost all hydrogen (approx. 99%) is currently produced by means of a process called *reforming*, whereby it is extracted from the methane molecule (*grey hydrogen*), from gasified coal (*black*) or from lignite (*brown*), collaterally producing carbon dioxide (CO_2). In some cases, Carbon Capture and Storage (*CCS*) is carried out during the reforming process, i.e. a process whereby the CO_2 is collected without being dispersed into the environment, thus making it usable as a resource. With the same production process, CCS reduces CO_2 emissions per kg of H_2 produced from 20.2 kg to 2.0 kg for black

hydrogen and from 8.9 kg to 0.9 kg for grey hydrogen [5]. Hydrogen produced by capturing CO_2 is referred to as *blue* and suffers a price increment due to the additional processes compared to when CCS is not used.
Produced according to these processes, hydrogen does not constitute a renewable resource, as in addition to requiring fossil raw materials, it merely relocates emissions in the production phase, without constituting a real zero impact on the ecosystem as a whole.
Hydrogen, being contained in water, can be obtained through a simple electrolysis reaction, which breaks down the H_2O molecule into hydrogen and oxygen. However, this reaction requires electricity, which constitutes a cost in economic and environmental terms affecting the sustainability of hydrogen. Where available, electricity from nuclear power plants is sometimes used to produce hydrogen, in this case called *violet*. This does not lead to CO_2 emissions as nuclear power plants do not emit any, but conversely produces nuclear waste, an effect that even countries with active power plants try to limit by favouring different production processes. The same electrolysis can take place with electricity produced from renewable sources. In this case, hydrogen is actually produced by a sustainable process with no significant negative effects and is called *green hydrogen*. The latter is, in most cases, the hydrogen of choice in projects to upgrade energy production processes and related investments.
The cost of producing hydrogen is strongly influenced by the cost of the energy resource used to produce it. BloombergNEF presents in [5] an overview of hydrogen costs at changing raw material prices in the period 2020-2050. An average value of $1.5/kg for grey hydrogen and $2.5/kg for black hydrogen can be taken as a reference. The relevant blue versions cost on average $0.5/kg more for the CCS process.
The cost of green hydrogen is currently the highest and depends on the price of renewable energy. To date, according to estimates from different sources, it ranges from 2.5 $/kg up to 14 $/kg, although according to [5] it is expected to be supplied to small consumers at an indicative price of 2.5 $/kg in 2030 to reach around 1 $/kg in 2050 due to the numerous investments that are globally affecting the production chain.

1.3 Hydrogen transformation

The hydrogen molecule is often used not directly, but as a chemical component in the production of derivatives. An example of this is the production of synthetic hydrocarbons, produced by combining CO_2 with hydrogen to make up fuel molecules with high specific energy, such as methane gas (by the methanation process) or methanol. In addition to the synthetic production of fuels, hydrogen is sometimes used as a virtual energy store: in fact, it can be produced and stored with the aim of chemically storing in it the energy produced by discontinuous power plants (such as renewables, in particular solar and wind power) at times of reduced demand. This process is called *Power-to-Gas* (abbreviated *P2G*), as the electrical power is converted into a gas that can later be used to supply energy when required, with numerous advantages over the use of traditional battery storage.

It also finds uses in contexts other than energy, such as the production of the ammonia molecule (NH_4), which is widely used as an ingredient in fertilisers.

1.4 Hydrogen transport

Due to the much lower energy density of hydrocarbons, transporting hydrogen presents a challenge for its widespread distribution and subsequent use in mass consumption. The cost of transport can exceed the cost of producing the resource, relegating it to costumers geographically not far from production sites. To date, hydrogen is transported in three distinct ways. Below are the cost estimates per mode presented by BloombergNEF in [6] for information.

For intercontinental journeys (distances over 1000 km) and volumes between 10 and 1000 tonnes per day, hydrogen tends to be transported in the form of ammonia in special ships, while for smaller journeys, heavy-duty road transport vehicles are used that store it in *Liquid Organic Hydrogen Carriers* (known as *LOHCs*), i.e. organic compounds containing hydrogen that are used as a method of hydrogen storage. The cost of these methods is approximately $3/kg by ship and can reach $6.7/kg for road transport.

For smaller movements, between 100 km and 1000 km, large volumes of hydrogen can be moved via transmission or distribution pipelines, at a cost of between 0.1 $/kg and almost 2$/kg, while smaller quantities can be moved by road for the transport of both LOHC and pure compressed hydrogen, at a higher price per unit between about 1$/kg and 4$/kg.

Movements on a local (1 km to 10 km) or urban (10 km and 100 km) scale face a lower cost, between 0.05 $/kg and 0.22 $/kg for pipeline transport and between 0.65 $/kg and 1.73 $/kg for road transport, which in this case is predominantly pure compressed hydrogen.

1.5 End uses of hydrogen

Hydrogen is currently used in a variety of different contexts, some of which are discussed in detail in the following chapters.

In industry, it is mainly used in processes involving steelmaking, as a substitute for coal, and in the chemical industry and refineries, where it is used as a component for a wide variety of molecules.

In the transport sector, it is a valid substitute for traditional fuels, due to the higher pollutant emissions of these. More and more vehicles are using an electric motor powered by a fuel cell, a device capable of generating electrical and thermal power using hydrogen, the operation of which is described in detail in the following chapter. Due to the high weight of this device, however, it is more widely used in large vehicles, such as ships, planes, trains and large trucks. According to IRENA [2], by 2021 there will be more than 40000 fuel cell-powered electric vehicles on the road worldwide, more than 90% of which will be in Korea, the US, China and Japan. IRENA also estimated 6000 electric buses (95% of them in China) and over 3100 trucks powered by this technology in 2020, which compared to the existing vehicle fleet represents a very small fraction.

The uses studied in this paper are stationary power and heat generation, where only a small fraction of the hydrogen used globally is currently used.

1.6 Aims and structure of the thesis

The aim of this research is to analyse the technical and economic feasibility of using hydrogen in the residential sector, where it is not yet widely used. In particular, the use of hydrogen as a sustainable resource for powering electrical and thermal generation systems using a fuel cell and thermal generation systems based on an H_2-ready boiler (capable of receiving a mixture of hydrogen and natural gas as fuel) is studied. Such a system is declined in several configurations, outlined below, of which it is at first analysed the energy performance and then the economic aspect, in order to calculate what the requirements are for a radical conversion of the current residential energy generation paradigm.

1.6.1 Production of a design tool

Parallel to the study outlined above, the aim of this research is to create a design tool useful for dimensioning and simulating a system based on these hydrogen generators by receiving the loads and characteristics of the users as input data.
This tool, realised in the form of a spreadsheet, operates according to the path described in this paper, and was used to process the data for the case study under consideration.

2 The fuel cell

The fuel cell is a device designed to produce electrical power through electrochemical reactions by combining hydrogen and oxygen, thus forming the water molecule. Being an exothermic reaction, a large amount of thermal energy is generated, which can be recovered through the cell's cooling circuit. This makes the cell a viable option for use as a stationary generator in a *Combined Heat and Power plant* (*CHP*).
Figure 2-1 shows a CHP system with a fuel cell.

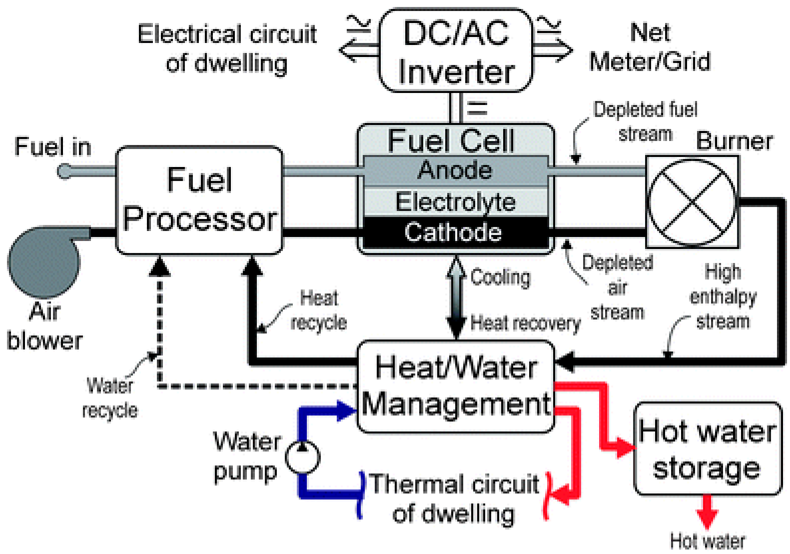


FIGURE 2-1: EXAMPLE OF A CHP SYSTEM WITH FUEL CELL. IMAGE FROM [7]

Due to the fact that combustion does not take place as it would in a conventional boiler and that there are no moving parts, the operation of this device is silent and does not emit pollutants. The efficiency of fuel cells is also much higher than in combustion processes, where much of the fuel energy is lost and does not reach the end consumer.

2.1 Types of fuel cells

Fuel cells differ mainly by the type of electrolyte used, which determines the types of fuel that can be used and the characteristics of their operation, such as the level of fuel purity tolerated and the temperature reached during operation.
Elmer et Al. in [8] present an overview of the main characteristics of fuel cell categories and the cell system.
The main types of fuel cells are:

1. Proton Exchange Membrane Fuel Cell (PEMFC)
2. Alkaline Fuel Cell (AFC)
3. Direct Methanol Fuel Cell (DMFC)
4. Phosphoric Acid Fuel Cell (PAFC)
5. Molten Carbonate Fuel Cell (MCFC)
6. Solid Oxide Fuel Cell (SOFC)

The operating temperatures of PEMFC, AFC and DMFC type cells are the lowest (80-250 °C), while PAFC, MCFC and SOFC type cells reach higher temperatures (250-1000 °C). The operating temperature is a factor to be taken into account when choosing which technology to adopt, as this determines some substantial differences, such as the quality of recoverable heat and the time required to reach working conditions after being switched off. The most widely used models are, for low temperatures, PEMFCs, and for higher temperatures, SOFCs. **Table 2-1** contains an overview of some characteristics of these cell types formulated by Arsalis in [9].

TABLE 2-1: DESCRIPTION OF THE TYPICAL CHARACTERISTICS OF FUEL CELLS. TABLE ADAPTED FROM [9]

Types of FC	Nafion-based PEMFC	PBI-based PEMFC	SOFC
Temperature	60–80 °C	140–180 °C	300–1000 °C
Net electrical efficiency	35–45%	35–45%	35–45%
System efficiency	75–90%	75–90%	75–90%
Advantages	High electrical efficiency, rapid start-up, high power density, proven technology, low emissions	High electrical efficiency, simple water management, compact and practical design, lower quality syngas can be used	High electrical efficiency, simple water management, enhanced kinetics, simple fuel processing
Disadvantages	Problematic water management, very high purity needed in syngas (less than 10 PPM), requires complicated fuel processing, expensive catalyst (platinum)	Short lifetime	Slow start-up and shut-down procedures, complicated heat recovery

2.2 The fuel cell system

In addition to the generator constituted by the cell, a system that can in practice satisfy a thermal and electrical load requires certain other components, which are described in [8] and briefly outlined below.

- **Fuel Processor**: Some cells use a hydrogen-rich hydrocarbon, such as natural gas, as fuel. These types of cells require a component that separates the hydrogen from the other elements in the fuel. Other types use pure hydrogen directly, not requiring this preliminary transformation.
- **Fuel cell stack**: The fuel cell stack is the component where hydrogen and oxygen are combined to produce electrical and thermal energy, and collaterally water. Fuel cells differ in their configuration and operation, with different stacks depending on the type considered. The polymer electrolyte membrane (PEM) and

solid oxide (SO) cell stacks are shown below. In **figure 2-2** is shown a stack of a PEMFC, while in **figure 2-3** is shown a stack of a SOFC.

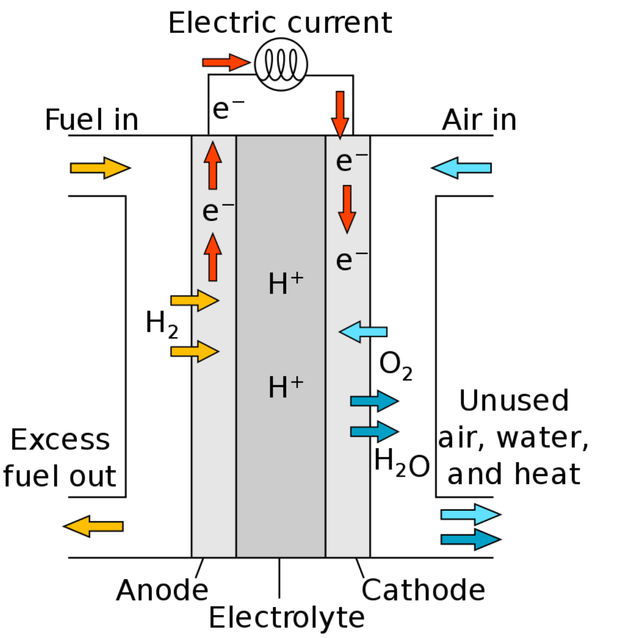


FIGURE 2-2: STACK OF A PEMFC. IMAGE FROM [10]

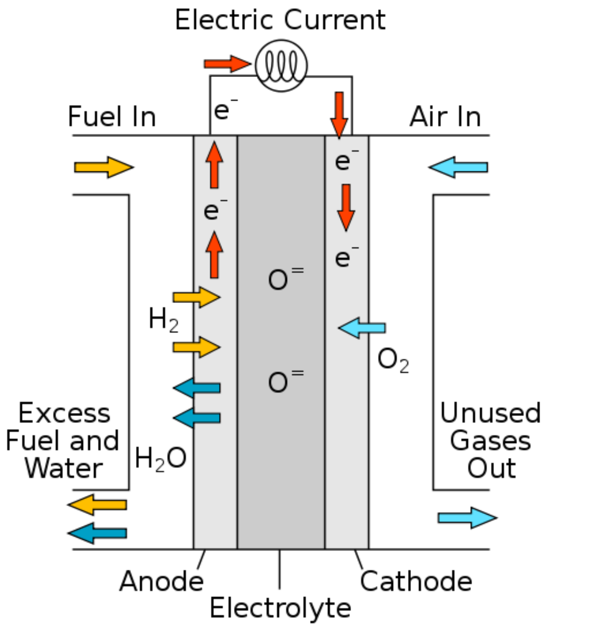


FIGURE 2-3: STACK OF A SOFC. IMAGE FROM [11]

- **Inverter DC/AC and connections to the grid and load:** Connected to the stack there is an inverter to convert the electrical output of the cell from direct current to alternating current. The electrical energy can then be delivered to the load or, if required, be delivered to the electrical grid.
- **Heat recovery system:** the hot fluids leaving the stack contain a large amount of heat, which must be extracted to allow the device to function properly. The extraction takes place by means of a heat recovery system that makes this resource available to satisfy a heat load, while improving both the overall efficiency of the system, which is almost doubled by the possibility of supplying this heat compared to the case of using it only as an electric generator, and the environmental performance. In the case of a stationary application in the residential sector, the recovery circuit can be connected directly to the thermal load of a building to satisfy it in real time or be used to charge a thermal storage system.
- **Components of Balance of Plant (BoP):** Various minor components are used to keep the system running, such as pumps, pipes, sensors and control systems. These components also include the air blower that supplies oxygen to the fuel processor.

2.3 Durability

A central factor among those that most affect the validity of fuel cell systems as substitutes for current technologies is certainly that of component durability, dealt with by Morocco et Al. in [12], from which some quantitative information is given below. Among the components to be taken into account, the stack stands out in particular, which alone accounts for about 27% of the total cost of the cell. The wear and tear of the stack has a negative effect on its efficiency, which can be quantified as a decrease of between 0.13% and 0.25% for every 1000 hours of operation. Another stress factor for the cell stack is the start-up, which, as pointed out by Torreglosa et Al. in [13], is equivalent in terms of wear to 3 hours of continuous operation.

The stack is generally replaced when its efficiency falls below 90% of its nominal value, and therefore its service life depends on how the device is operated. On the basis of the above-mentioned data and according to data from manufacturers reported in [8], it is possible to estimate the number of operating hours between 30000 and 80000 before the stack needs to be replaced. An average lifespan can more conservatively be estimated to be between 30000 [12] and 50000 [8] hours, considering the realistic utilisation of the stack in a fuel cell and the worsening contribution of start-up wear.

2.4 Efficiency

The efficiency values of the fuel cell, defined as the ratio of the power produced (electrical, thermal or overall) to the calorific value of the fuel consumed, depend on the type of cell and even more particularly on the operating point, i.e. the percentage of power output in relation to the rated power. For a correct simulation of a fuel cell system, it is necessary to know precisely how the efficiency values vary as the power output varies. This operating curve can be produced experimentally or obtained from the device manufacturers. In general, a higher electrical efficiency corresponds to a lower thermal efficiency.

Below is reported an example of a PEM-type cell efficiency curve which can be found in [12], by Morocco et Al., that detail the electrical efficiency values and specify how the consumption of the auxiliaries varies with the variation of the electrical power supplied. **Figure 2-4** shows a graph with the electrical efficiency of the cell and the electrical efficiency of the entire system, obtained considering that the auxiliaries are supplied by the cell itself.

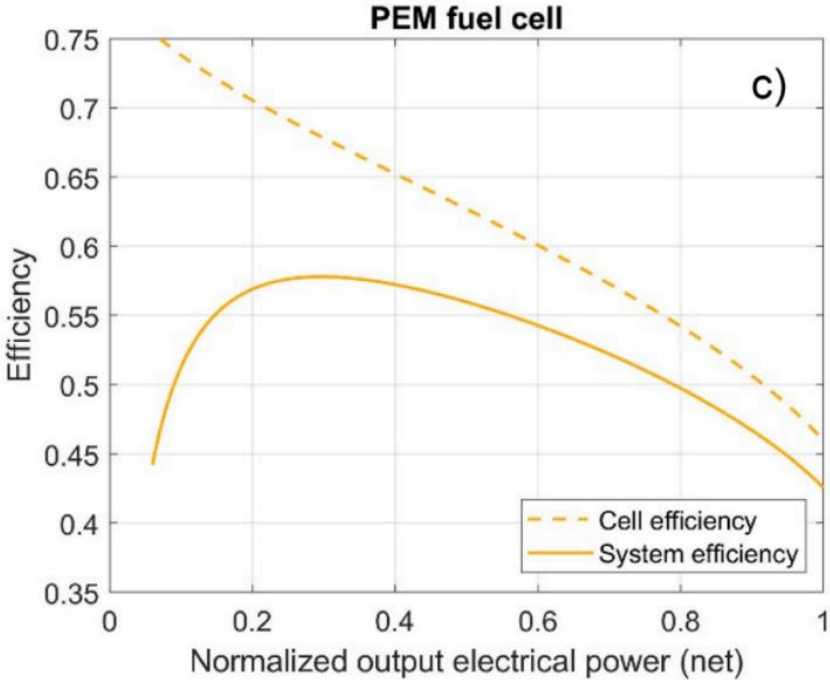


FIGURE 2-4: ELECTRICAL EFFICIENCY OF A CELL AND ITS SYSTEM. IMAGE FROM [12]

The thermal efficiency at each operating point of a cell can be estimated by knowing the values of input fuel flow rate, electrical efficiency and consumption of the auxiliary devices under those conditions.

3 The hydrogen supply issue

Due the fact that the possibility of continuously receiving hydrogen through a capillary distribution network as is the case with natural gas is currently not available, residential systems that use it must necessarily equip themselves with an efficient and safe supply method suitable for providing a sufficient quantity of gas to meet the required energy needs. The supply of the hydrogen resource varies according to the type of consumer.

In the case of consumers located in remote locations, unable to connect to the electricity and gas distribution networks, plants powered by renewable sources (mainly solar, wind and hydroelectric) are commonly used to meet a high percentage of the required load, while the remainder is supplied by generators powered by fossil fuels, which enjoy high reliability and energy density.

In these cases, the cost of energy is considerably higher than the average, and therefore on-site green hydrogen production, which is generally too expensive for small-scale plants, can be considered.

Green hydrogen generation plants make it possible to convert surplus renewable energy into a storable resource, decoupling consumption from production and thus obviating the intermittency that often characterises renewables. The cost of electrolysers and consequently the final cost of energy is higher the smaller the size of the generation plant, and in general the cost of green hydrogen reaches three times the cost of grey hydrogen produced through steam reforming from methane gas [5]. A key requirement for in-situ hydrogen production is an abundant availability of renewable sources, which often

translates into a large amount of space where photovoltaic panels or wind turbines can be installed.
This availability of space is undoubtedly a problem for more urbanised contexts. Hydrogen supply for residential buildings in more populated centres can be conceived as a periodic delivery to the user of hydrogen produced elsewhere, stored in dedicated spaces awaiting consumption.

3.1 Standards

As hydrogen-powered devices for stationary use are not yet widely available, the Italian state regulations in this regard are currently rather lacking, and projects need to be discussed with the relevant authorities with regard to safety standards. The situation is dealt with in depth by the *Italian Hydrogen and Fuel Cells Association* (*H2IT*) in [14] of which the main points are summarised below.
The most common storage systems for stationary applications are hydrogen gas systems requiring compressed gas tanks with pressure up to of 1000 bar. To date, national legislation is lacking in specific hydrogen applications, which are only considered in the Ministerial Decree of 23 October 2018 "Regola tecnica di prevenzione degli incendi per la progettazione, costruzione ed esercizio degli impianti di distribuzione dell'idrogeno per autotrazione". This Decree details the minimum safety distances to be observed and sets limits for the maximum storage pressure (equal to 1000 bar) and the maximum quantity of hydrogen in storage (equal to 6000 Nm^3).
With regard to the design of storage facilities, it is indicated that these must be constructed according to the rule of art, for which reference is made to standard ISO 19884.
In the case of applications in urban areas, the above limits are even stricter: storage not exceeding 500 Nm^3 of gas and on-site production not exceeding a capacity of 50 Nm^3/h.
H2IT adds that the above-mentioned Decree cannot be extended as a reference for stationary residential/commercial hydrogen storage, for which uses, among other things, even the maximum storage pressure required is generally lower than the 700 bar required for automotive use.
For the purposes of authorisations for the uses under examination, it is therefore said that is appropriate to refer to Presidential Decree 151/2011, which identifies the activities subject to fire prevention controls and regulates, for the filing of projects and the examination of projects, for technical inspections, for the approval of exceptions to specific regulations, the verification of fire safety conditions that, under current regulations, are attributed to the competence of the Corpo Nazionale dei Vigili del Fuoco.
Part of the safety requirements to be met can be assumed by analogy with the requirements for natural gas treatment mentioned in the Ministerial Decree of 3 February 2016 "Approvazione della regola tecnica di prevenzione incendi per la progettazione, la costruzione e l'esercizio dei depositi di gas naturale con densità non superiore a 0,8 e dei depositi di biogas, anche se di densità superiore a 0,8" [15], which decree provides guidance on safety distances both in cases where the storage facility is stationary and where it consists of a mobile unit.

Once the hydrogen requirements of the consumer and the characteristics of the storage facility are known, it is possible to check what the requirements are for storage space.

3.2 Storage modes

There are currently several ways of storing hydrogen, from the most common compressed and liquid hydrogen systems to new processes still being studied or engineered, such as chemical (metal hydrides, ammonia, hydrocarbons) and physical (nanotubes) hydrogen absorption [14]. As noted above, the most common mode is the storage of hydrogen in gaseous form in a pressure vessel and it is one of the most cost-effective [6]. Due to the low volumetric energy density of hydrogen, there is a need for devices capable of storing it at a pressure level as high as possible, while at the same time reducing storage space and the number of refuelling operations required. Conversely, high pressures require safety limits, which can easily lead to a regulatory impossibility. For the case study costumer, two conceptually different systems were considered.

3.2.1 Stationary storage

The first consists of a single large tank at lower pressure. The advantages of using such a configuration lie in the possibility of limiting safety constraints due to the lower pressure. At the same time, a single tank occupies a very large volume, which can be critical during refilling. According to a preliminary analysis, an apartment building-sized user with a hydrogen demand of five tonnes could use a device such as the one shown in **figure 3-1** and described in **table 3-1**:

FIGURE 3-1: STATIONARY LOW-PRESSURE STORAGE - 70 BAR BAGLIONI TANK. IMAGE FROM [16]

TABLE 3-1: STATIONARY LOW-PRESSURE STORAGE SPECIFICATIONS [16]

Manufacturer:	Baglioni (IT)
Pressure:	70 bar
Capacity:	100 mc; 570 kg

Annual refills planned:	8.5
Mass (empty):	79200 kg vertical; 77500 kg horizontal
Diameter:	2.392 m
Height:	25.5 m

Due to the prohibitive size of this solution, it is considered unsuitable for use with residential users.

3.2.2 Mobile storage

A second viable option for the storage system is to use a mobile tank, i.e. a tank that is delivered loaded and replaced after it has been depleted. Such storage generally consists of a set of several small, high-pressure cylinders secured to the trailer of a lorry, and is called a *tank wagon*. The overall dimensions of the tank wagon are defined according to the user load. Assuming an annual requirement of five tonnes of hydrogen, a wagon consisting of ten cylinders similar to those shown in **figure 3-2** and then described in **table 3-2** can be assumed:

FIGURE 3-2: MOBILE HIGH-PRESSURE STORAGE – CYLINDERS "MAHYTECH TANK – 500 BAR". IMAGE FROM [17]

TABLE 3-2: HIGH-PRESSURE STORAGE SPECIFICATIONS [17]

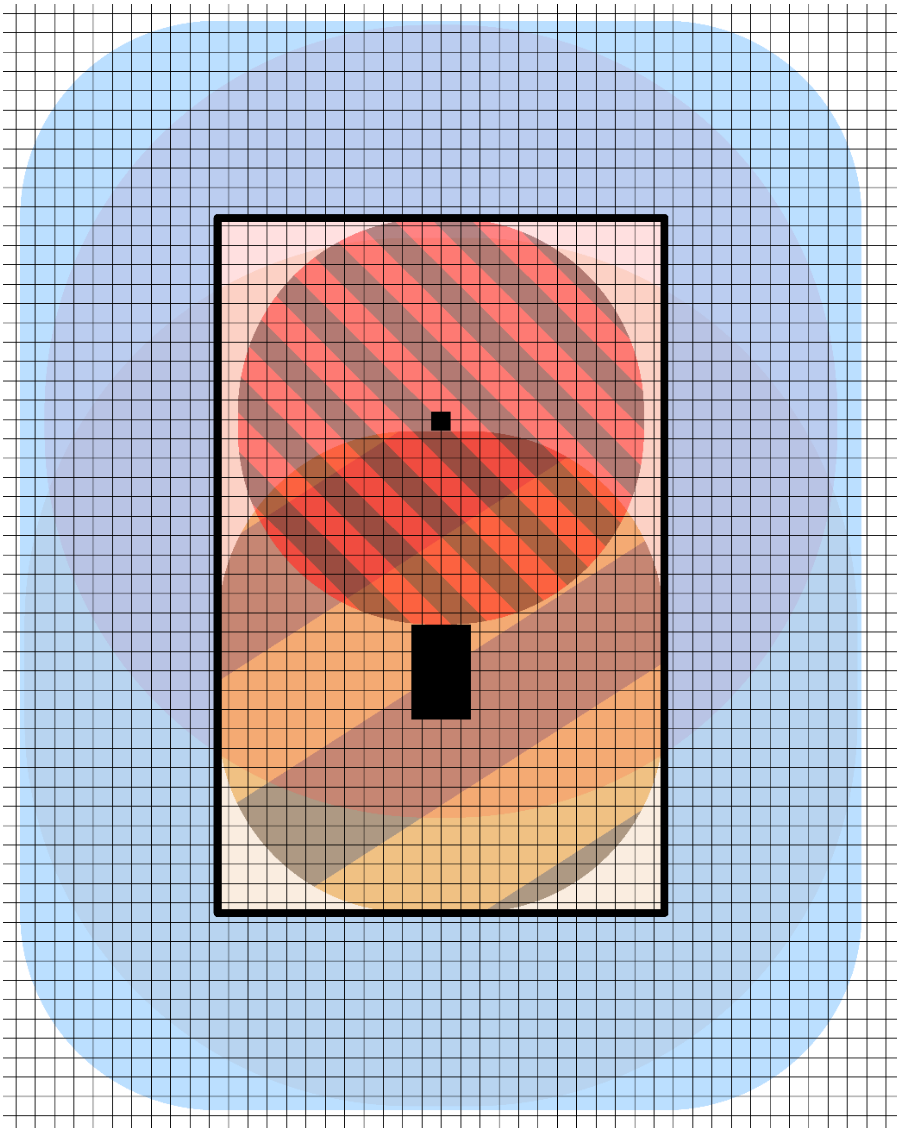
Manufacturer:	Mahytec (FR)
Pressure:	500 bar
Capacity:	300 L; 9.5 kg
Annual refills planned:	512 cylinders (10 cylinders per week)
Mass (empty):	240 kg
Diameter:	48 cm
Height:	307 cm

Given the modular nature and the smaller space requirement, the tank wagon configuration is considered more suitable for an urban user, oriented moreover towards facilitating loading and unloading operations without the need to refill the tank at the user's location.
In accordance with the regulations in force, the area to be allocated to hydrogen storage is quantified.

3.3 The hydrogen plant

Since this is a high-pressure compressed gas, the regulations [15] details the safety constraints to be respected, among which the safety distances that pressurised gas elements, defined as *hazardous elements*, must respect between each other and between other elements of the complex (perimeter walls, surrounding buildings, etc.) appear to be the most impactful.
There must be an internal safety distance of ten meters between two elements such as the fuel cell and the tank car that feeds it, and a safety distance of 20 m between each of these two elements and the nearest building area. The hydrogen treatment area must then be limited by walls to prevent access by unauthorised personnel. In **figure 3-3** is reppresented a plan of the overall footprint of a power station built according to these requirements, in which the grid unit represents a distance of one meter.
Overall, the plan shown is approximately 44 m wide and 55 m high.

FIGURE 3-3: THE HYDROGEN PLANT EXTENSION. ONE SQUARE IS EQUIVALENT TO 1 SQUARE METER



The figures in black on the inside represent the fuel cell, top, and the tank car, bottom, respectively. The perimeter wall is depicted in black. The black-banded field represents the internal safety distance between one element and another, while the blue area represents the space without building elements outside the power station.
A square in the figure represents an area of one square metre.

3.4 Conclusions on procurement

The upgrading of the complex of residential buildings that currently use natural gas and electricity from the grid to meet their needs is hampered by current regulations that severely limit the deployment of hydrogen generation plants. The need to have an extremely large area available for the hydrogen power plant makes the solution of supplying a hydrogen storage facility at the user's premises completely impractical. For the purpose of the case study, it will be assumed that hydrogen gas will be available from the grid as is currently the case with natural gas.

4 Methodology

This chapter outlines the methodology employed in this research. For each system solution, its characteristics are described and the simulator's process to calculate the energy and economic metrics is explained.
The performance of the studied systems is analysed over the course of a calendar year, assuming that the shortest time unit is one hour. According to this assumption, all the studied quantities, with no instantaneous variations, are assumed constant within each hour. This simplification is essential when dealing with the data of the case study, formulated in a similar manner, as it would be reasonably necessary when analysing the data of a generic consumer.

4.1 Energy demand calculations

The heat demand for heating the case study building was calculated using the material provided by Prof. Vincenzo Corrado elaborated in the previous publication [18]. The temperature profile reports for each hour of a calendar year the building's heat demand, calculated according to the standard UNI EN ISO 52016-12018. Both the total demand and the required peak heat output are calculated from the load profile.

The electricity requirements were calculated by estimating for each service in the common areas or housing units (lighting, use of specific household appliances, etc.) the consumption required and the relative number of hours of use, also obtaining for the electricity requirements an estimate of the hour-by-hour consumption profile for a calendar year. This calculation was carried out by means of an internal calculation tool provided by the company C2R Energy Consulting and designed by PhD. Paduos. The total and peak electrical demand is calculated from the electrical load profile.

The heat demand for domestic hot water in the building is calculated using the standard EN 16798-1:2019, and is available in the same form as the other profiles (energy required hour by hour, over the period of one year).

4.2 Plant options investigated

The hydrogen generation plant can present different configurations, which are described in detail below.

4.2.1 Fuel cell and conventional boiler plants

In this scenario (**figure 4-1**) a fuel cell as the electrical generator and a traditional boiler as the thermal generator (in addition to the heat produced by the cell itself) are present. This scenario may be the result of a redevelopment operation where the consumer, with access to hydrogen, chooses to install a fuel cell to discontinue purchasing electricity from the grid.

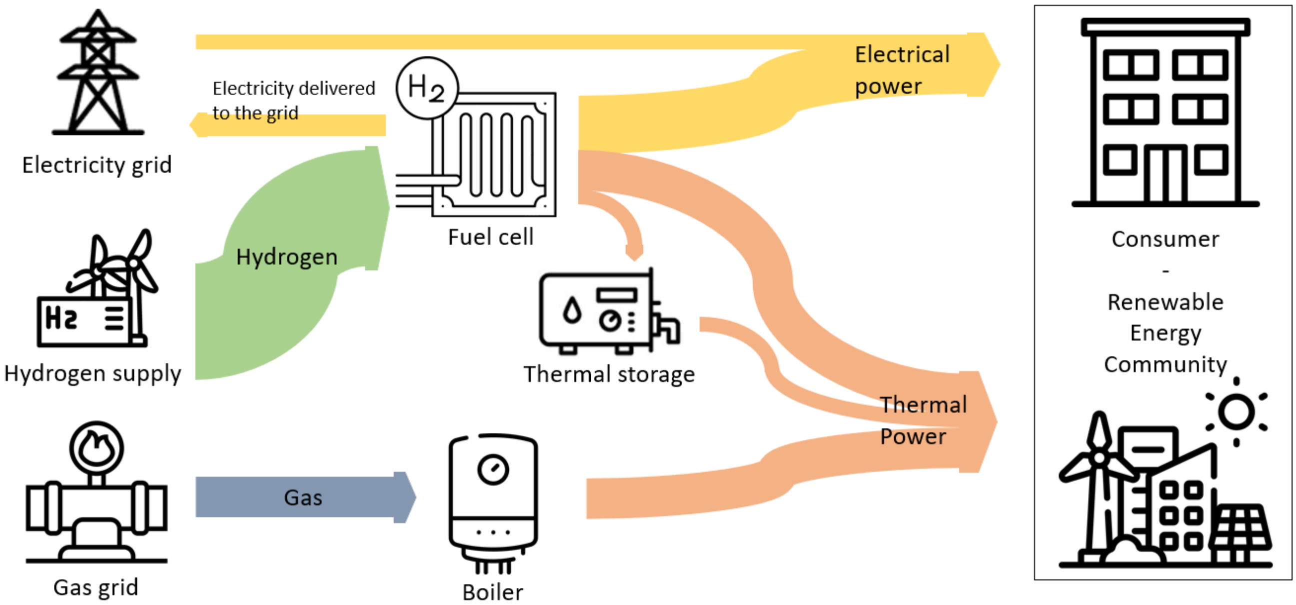


FIGURE 4-1: FUEL CELL AND CONVENTIONAL BOILER SYSTEM

The hydrogen, assumed to be available from the grid, powers a fuel cell sized to fulfil the building's total electricity demand. As part of its operation, the fuel cells produce a significant quantity of heat, which is recovered through the cell's cooling circuit and is immediately available to meet the current thermal energy demand.

If a substantial excess of heat is estimated, it can be stored in a storage system, a concept discussed in more detail below. The possibility of using this heat by feeding it into a district heating network of a renewable energy community is also considered.

An auxiliary boiler (assumed for simplicity to be a traditional gas boiler) is available to produce any required heat not supplied by the fuel cell or storage, which can be the previous thermal generation system of the consumer.

The generation of electricity through the cell can take place in two conceptually distinct ways, resulting in two different scenarios detailed below.

4.2.1.1 Scenario 1: Fuel cell operating in load-following mode

In this scenario, it is assumed that the fuel cell delivers the required electrical power hour by hour with an ideal load adhesion. Therefore, the fuel cell is sized with enough power to meet the utility's peak electrical power demand.

This operating regime allows the complete satisfaction of consumer's electrical load without the need for grid connections. Grid connections may be arranged, or not removed if already in place, to serve as a useful redundancy element ensuring a level of security against potential generator outages. The production of heat from the cell is non-linearly linked to the production of electricity, according to the operating point efficiencies imposed by the supplied electrical power.

Conversely, installing a large generator may entail high initial investment costs and generally operates in a regime far from optimal efficiency conditions, leading to increased hydrogen consumption for the same amount of electricity generated.

Figure 4-2 summarises the simulator's path to analyse this scenario for a generic utility, incorporating the presence of the thermal storage system and the sale of heat via district

heating (which can be excluded during program initialization for scenarios without them). If excluded, the algorithm ignores the steps concerning these aspects.
Subsequently, the path is illustrated step by step. It should be noted that passages concerning electricity are highlighted in yellow for enhanced legibility, while those related to heat energy are marked in red, and those related to economic calculations are in green.

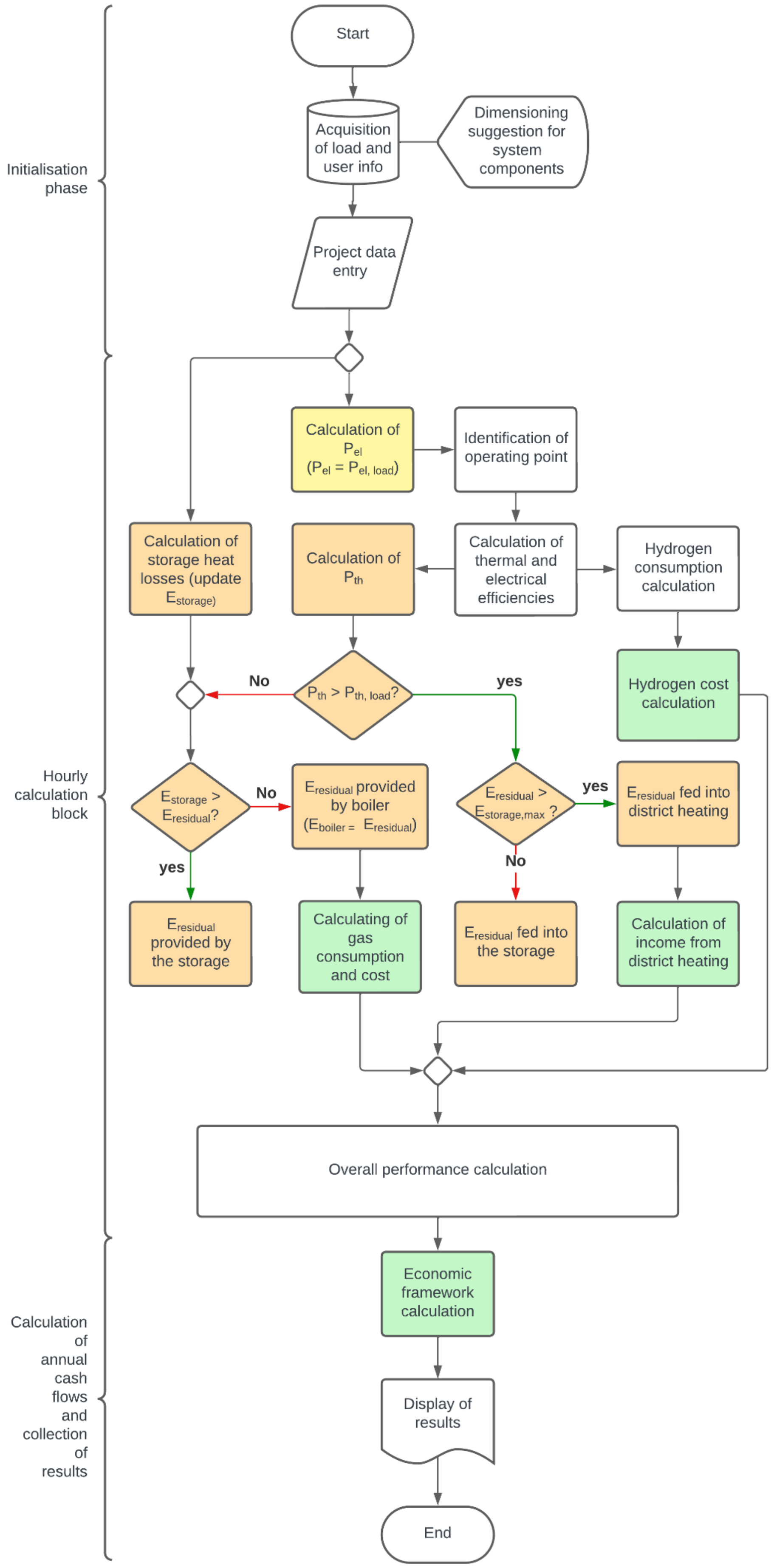


FIGURE 4-2: SCENARIO 1, SIMULATOR ALGORITHM

The simulator performs the following steps to compute the scenario:

1. **Initialisation phase:** The designer enters some design variables into a control panel, including the option to include domestic hot water service, the presence of thermal storage (with specified characteristics), and the connection to the district heating network. Once this data is set, the simulator suggests the nominal power value for the fuel cell. The designer then finalizes the initialisation by choosing the cell power.
   Having set this initial data, the simulator proceeds with the hourly calculation of the generation plant's performance following these steps for each hour.
2. **Calculation of the generated electrical power:** The electrical power generated by the cell, in this scenario, is equal to the electrical power required by the utility. It should be noted that the fuel cell can deliver a minimum electrical power of 6% of the nominal electrical power (known as the cut-off power). The value of electrical power delivered is therefore equal to:

$$P_{el} = \max(P_{el,load};\ P_{nom,1} * c_{cut-off})$$

Where:

P_{el}: electrical power generated

$P_{el,load}$: electrical power required that hour by the utility

$P_{nom,1}$: nominal electrical power of the cell

$c_{cut-off}$: cut-off coefficient (equal to 6 %)

Once P_{el} is defined, the operating point of the cell for that hour is determined.

3. **Calculation of efficiencies:** Given the power output, the optimiser calculates the electrical and thermal efficiencies (η_{el} and η_{th}) by comparing the power output with the fuel cell's operating curve in its own data.
4. **Calculation of the generated heat output:** The heat output generated by the cell is calculated as:

$$P_{th} = \frac{P_{el}}{\eta_{el}} * \eta_{th}$$

Where:

P_{th}: thermal power generated

P_{el}: electrical power generated

η_{el}: electrical efficiency of the cell

η_{th}: thermal efficiency of the cell

5. **Calculation of storage system losses:**
   Heat loss from storage is calculated according to a method detailed below. This heat loss is called E_{loss}

6. **Calculation of the required thermal energy not produced by the cell:** Knowing the thermal power generated in that hour, it is compared with the thermal

power required by the utility in the same period to calculate the amount of energy required but not produced by the cell, as follows:

$$E_{residual} = (P_{th,load} - P_{th}) * 1\ h$$

Where:

$E_{residual}$: thermal energy required by the utility not produced by the cell
$P_{th,load}$: heat output required by the user
P_{th}: generated heat output

If $E_{residual}$ is positive, it represents the energy to be supplied to the consumer via storage or boiler. If negative, it represents the surplus energy produced by the cell that can be stored in the storage or supplied to the district heating..

7. **Calculation of energy exchanged with heat recovery:** The value of $E_{residual}$ is analysed. If it is greater than zero, the maximum amount of heat available in the storage tank is drawn to meet the load without using the boiler. This quantity is calculated as follows:

$$\begin{cases} E_{residual} > 0 \\ E_{exchanged} = -\min(E_{residual};\ E_{storage} - E_{loss}) \end{cases}$$

Where:

$E_{exchanged}$: thermal energy exchanged with thermal storage
$E_{residual}$: thermal energy required by the utility not produced by the cell
$E_{storage}$: thermal energy in thermal storage
E_{loss}: thermal energy lost from storage

In the event of energy withdrawal, $E_{exchanged}$ assumes a negative value. If $E_{residual}$ is less than zero, this surplus heat needs to be stored to the district heating network. In this case $E_{exchanged}$ takes a positive sign, according to the convention of taking deposited heat in the recovery system as positive, as follows:

$$\begin{cases} E_{residual} < 0 \\ E_{exchanged} = -E_{residual} \end{cases}$$

Where:

$E_{exchanged}$: thermal energy exchanged with thermal storage
$E_{residual}$: thermal energy required not produced by the cell

8. **Calculation of available energy in storage**: The thermal energy available in the heat store is calculated by considering the amount of energy available in the previous hour, the energy exchanged in the current hour, and the heat losses during the past hour. The heat storage capacity is defined during initialisation and represents the maximum value that can be stored. If this capacity is reached, the surplus energy is directed to district heating. In this

case, the calculation takes the following form:

$$\begin{cases} E_{storage,h-1} + E_{exchanged} - E_{loss} > E_{storage,max} \\ E_{storage,h} = E_{storage,max} \end{cases}$$

Where:

$E_{storage,h-1}$:	energy present in the storage tank in the previous hour
$E_{exchanged}$:	thermal energy exchanged with thermal storage
E_{loss}:	thermal energy lost from storage
$E_{storage,max}$:	storage heat capacity
$E_{storage,h}$:	energy present in the storage tank during the calculated hour

If the amount of storable energy is less than the capacity, the calculation is carried out as:

$$\begin{cases} E_{storage,h-1} + E_{exchanged} - E_{loss} < E_{storage,max} \\ E_{storage,h} = E_{storage,h-1} + E_{exchanged} - E_{loss} \end{cases}$$

Where:

$E_{storage,h-1}$:	energy present in the storage tank in the previous hour
$E_{exchanged}$:	thermal energy exchanged with thermal storage
E_{loss}:	thermal energy lost from storage
$E_{storage,max}$:	storage heat capacity
$E_{storage,h}$:	energy present in the storage tank during the calculated hour

9. **Calculation of energy fed into district heating**: The surplus energy produced by the cell is fed into the district heating network under two conditions: when the storage tank is fully charged or absent. In the first case, the calculation is as follows:

$$\begin{cases} E_{storage,h-1} + E_{exchanged} - E_{loss} > E_{storage,max} \\ E_{D.H.} = E_{storage,h-1} + E_{exchanged} - E_{loss} - E_{storage,max} \end{cases}$$

Where:

$E_{storage,h-1}$:	energy present in the storage tank in the previous hour
$E_{exchanged}$:	thermal energy exchanged with thermal storage
E_{loss}:	thermal energy lost from storage
$E_{storage,max}$:	storage heat capacity
$E_{D.H.}$:	thermal energy fed into the district heating network
$E_{storage}$:	thermal energy in thermal storage

If storage is not present, the energy fed into the district heating network equals the energy exchanged calculated above and the formula takes this form:

$$\begin{cases} E_{exchanged} > 0 \\ E_{D.H.} = E_{exchanged} \end{cases}$$

Where:

$E_{exchanged}$: thermal energy exchanged with thermal storage

$E_{D.H.}$: thermal energy fed into the district heating network

When $E_{exchanged}$ has a negative value, $E_{D.H.}$ is set to zero. In this scenario, district heating is not used as a heat source but is considered as a virtual storage. This decision is motivated by the intention to represent cases where the district heating network is designed specifically for the disposal of the heat produced by this type of plant.

10. **Calculation of the thermal energy produced by the boiler:** The thermal energy produced by the boiler is defined as the difference between the required thermal energy not produced by the cell and that taken from the storage tank. The equation is as follows:

$$E_{boiler} = E_{residual} - E_{exchanged}$$

Where:

E_{boiler}: thermal energy produced by the boiler

$E_{residual}$: thermal energy required not produced by the cell

$E_{exchanged}$: thermal energy exchanged with thermal storage

When $E_{residual}$ is less than zero (when the cell produces excess heat), the value of $E_{exchanged}$ has the same absolute value but opposite sign, effectively cancelling the energy required from the boiler.

The simulator then proceeds with the calculation of resource consumption and associated costs.

11. **Calculation of hydrogen consumption:** Hydrogen consumption is calculated by knowing the electrical power output and its relative efficiency value. The formula used is:

$$V_{H2} = \frac{P_{el} * 1h}{\eta_{el} * LHV_{H2,v}}$$

Where:

V_{H2}: volume of hydrogen consumed

P_{el}: electrical power generated

η_{el}: electrical efficiency of the cell

$LHV_{H2,v}$: lower volumetric calorific value of hydrogen

The cost or revenue is then calculated for each resource, again on an hourly basis.

12. **Electricity Cost Calculation:** As is well known, the cost of purchasing electricity changes during a day or on particular days such as holidays. The

simulator has among its data the electricity billing time slot information for all hours of the year and is able to analyse each hour of the load to determine which slot it belongs to. In addition, the price difference between the purchase and sale of energy is taken into account, including taxes on sales earnings. When the load exceeds the production, the electricity cost is then calculated as:

$$\begin{cases} P_{el,load} > P_{el} \\ c_{el,h} = \left(P_{el,load} - P_{el}\right) * 1h * c_{el,buy} \end{cases}$$

Where:

$c_{el,h}$: cost (or yield) of electricity in the calculated hour
$P_{el,load}$: electrical power required by the utility
P_{el}: electrical power generated
$c_{el,buy}$: electricity purchase cost in the hourly billing band

When the electrical power generated is greater than the power required (in this scenario, this occurs only for load values below the cut-off power), the electrical energy is sold into the grid, and the cost takes on a negative value, representing revenue, calculated as:

$$\begin{cases} P_{el} > P_{el,load} \\ c_{el,h} = \left(P_{el,load} - P_{el}\right) * 1h * c_{el,sell} * (1 - tax) \end{cases}$$

Where:

$c_{el,h}$: cost (or yield) of electricity in the calculated hour
$P_{el,load}$: electrical power required by the utility
P_{el}: electrical power generated
$c_{el,sell}$: electricity sale cost in the hourly billing band
tax: percentage tax on sales

13. **Calculation of the cost of thermal energy:** Similar to electricity, when the amount of energy produced by the boiler is known, the amount of gas required to produce is calculated. In formula:

$$\begin{cases} E_{boiler} > E_{D.H.} \\ c_{th,h} = E_{boiler} * c_{gas,buy} \end{cases}$$

Where:

$c_{th,h}$: cost of thermal energy in the calculated hour
E_{boiler}: thermal energy produced by the boiler
$E_{D.H.}$: thermal energy fed into the district heating network
$c_{gas,buy}$: gas purchase cost

When the heat produced is delivered to the district heating, its revenue is calculated.

$$\begin{cases} E_{D.H.} > E_{boiler} \\ c_{th,h} = -E_{D.H.} * c_{gas,sell} * (1 - tax) \end{cases}$$

Where:

$E_{D.H.}$:	thermal energy fed into the district heating network
E_{boiler}:	thermal energy produced by the boiler
$c_{th,h}$:	yield of thermal energy in the calculated hour
$c_{gas,sell}$:	gas sale cost
tax:	percentage tax on sales

If no district heating energy is sold, the value of $E_{D.H.}$ would be zero, and only the purchase cost of gas would be calculated.

14. **Hydrogen cost calculation:** The hydrogen cost is then calculated by knowing the purchase price and the volume consumed.

$$c_{H2} = V_{H2} * c_{H2,buy}$$

Where:

c_{H2}:	cost of the hydrogen resource in the calculated hour
V_{H2}:	volume of hydrogen consumed
$c_{H2,buy}$:	hydrogen purchase price

15. **Calculation of the total cost of resources:** Finally, the costs and returns for each resource are added up to calculate the overall economic balance for the hour. In formula:

$$c_{tot,h} = c_{el,h} + c_{th.,h} + c_{H2,h}$$

Where:

$c_{tot,h}$:	total cost of resources in the calculated hour
$c_{el,h}$:	cost (or yield) of electricity in the calculated hour
$c_{th,h}$:	cost (or yield) of thermal energy in the calculated hour
$c_{H2,h}$:	cost of the hydrogen resource in the calculated hour

4.2.1.2 Scenario 2: Fuel Cell in a constant operating regime

In this scenario, it is assumed that the fuel cell constantly supplies the same electrical power. The exact value is in the amount needed to produce in one year the entire electrical load required in the same period by the consumer.

The size of the fuel cell can be considerably smaller than in load-following operation, which has a positive effect on the initial investment cost and can be sized to operate at maximum efficiency.

In this operating regime, the connection to the electricity grid is necessary since the generation of electrical power is decoupled from the load. When the required load exceeds the supplied power, the power not met by the generator must be taken from the grid. Similarly, when the generated power exceeds the requested load, the difference must be fed into the grid.

In this scenario, it is therefore necessary for the utility to adopt with the *Gestore Servizi Energetici* (*GSE*) a self-consumption formula as purchase & resale, which allows to sell to the grid the amount of self-produced and not contextually consumed electricity. **Figure 4-3** summarises the path followed by the simulator for the analysis of this scenario, which is again set out step by step.

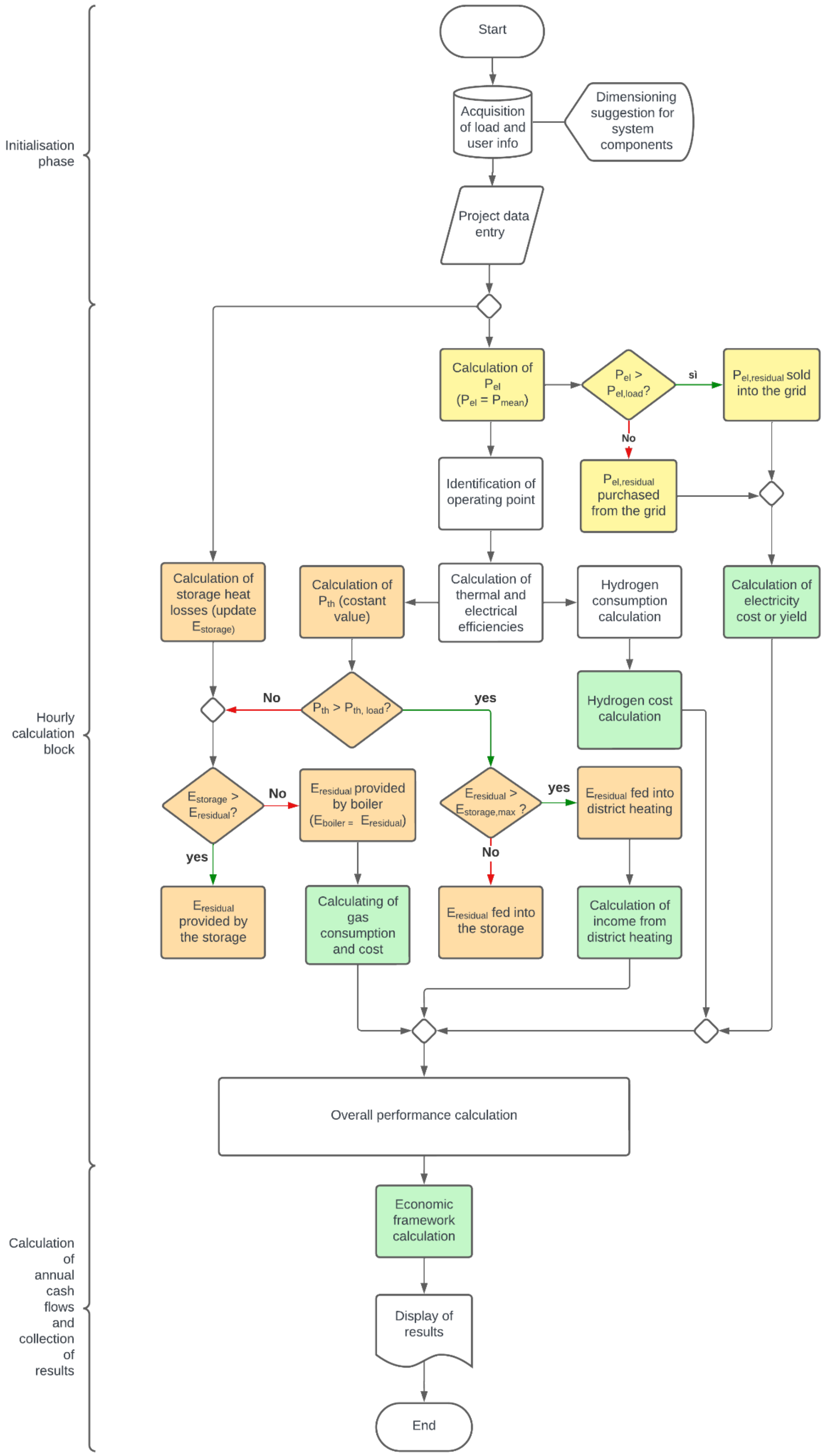


FIGURE 4-3: SCENARIO 2, SIMULATOR ALGORITHM

For this scenario, the simulator performs almost all the steps described for scenario 1, receiving the same utility information from the designer and calculating the same quantities. The only difference is that it calculates the electrical power produced as follows:

1. **Calculation of electrical power generated:** The electrical power generated by the cell, in this scenario, is assumed to be equal to the average annual power required by the consumer. During initialisation, however, the operator can arbitrarily set the nominal power of the cell, ignoring the size calculated as optimal for reducing hydrogen consumption. In this case, the simulator takes into account that it cannot produce more power than the nominal power. At the same time it can process the scenario even for nominal power values lower than the recommended one. In the formula, the nominal power value is calculated as:

$$P_{el} = min\left(\frac{E_{el,load,yearly}}{8760\ h}; P_{nom,2}\right)$$

Where:
P_{el}: electrical power generated
$E_{el,load,yearly}$: electricity required in the year by the utility
$P_{nom,2}$: nominal cell power

If a lower than the average power required value is chosen, the assumption that the electrical load would be completely satisfied by the cell would be violated. This case is not dealt with in this paper, but can nevertheless be calculated using the simulator in order to be able to study the solutions available for others costumers.

4.2.2 Hydrogen boiler plant

In this scenario (**figure 4-4**) hydrogen is only used to power a thermal generator capable of receiving a mixture of hydrogen and natural gas. Consumer's electrical load will then be met in the traditional way (i.e. through the purchase of energy from the grid or through other generators that may be present and are not the subject of this study).

Since there is no involuntary power generation in this case, this scenario is not ideally suited for powering an energy community. The introduction of a mixture of hydrogen and natural gas leads to an overall reduction in emissions proportional to the percentage of hydrogen in the mixture. Under the assumption adopted in this paper of using only green hydrogen, the energy input provided by hydrogen would result in almost zero pollutant emissions.

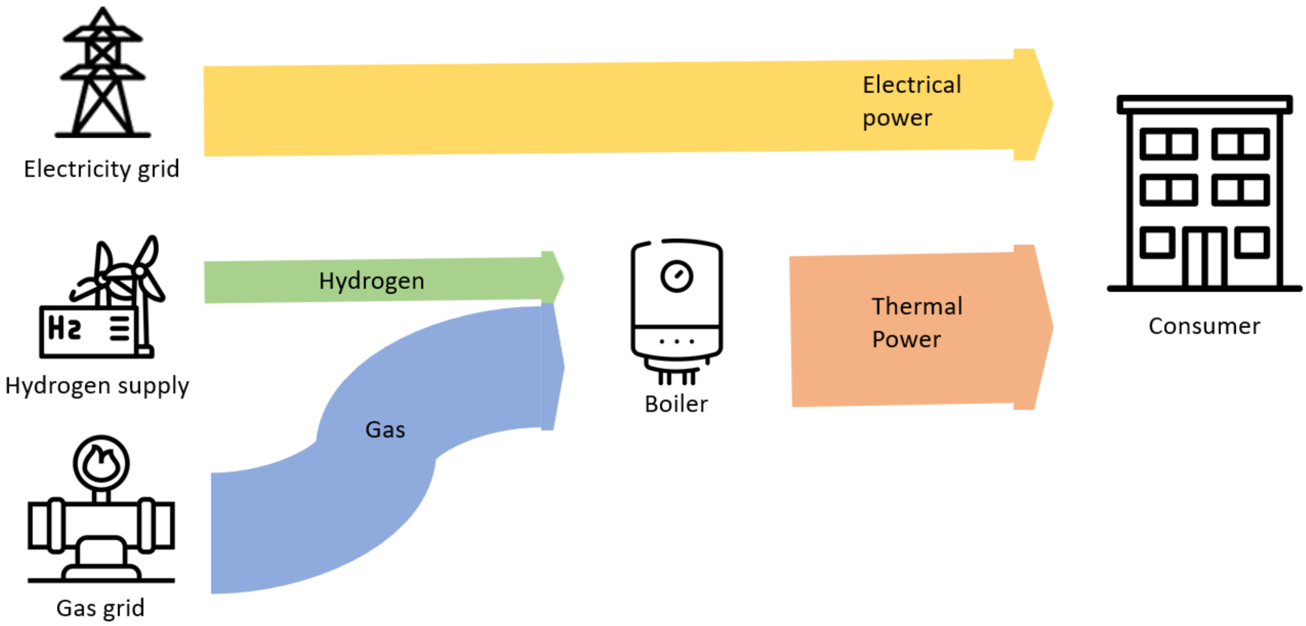


FIGURE 4-4: HYDROGEN BOILER SYSTEM

Figure 4-5 summarises the path followed by the simulator in analysing this scenario. The steps taken are then described in detail.

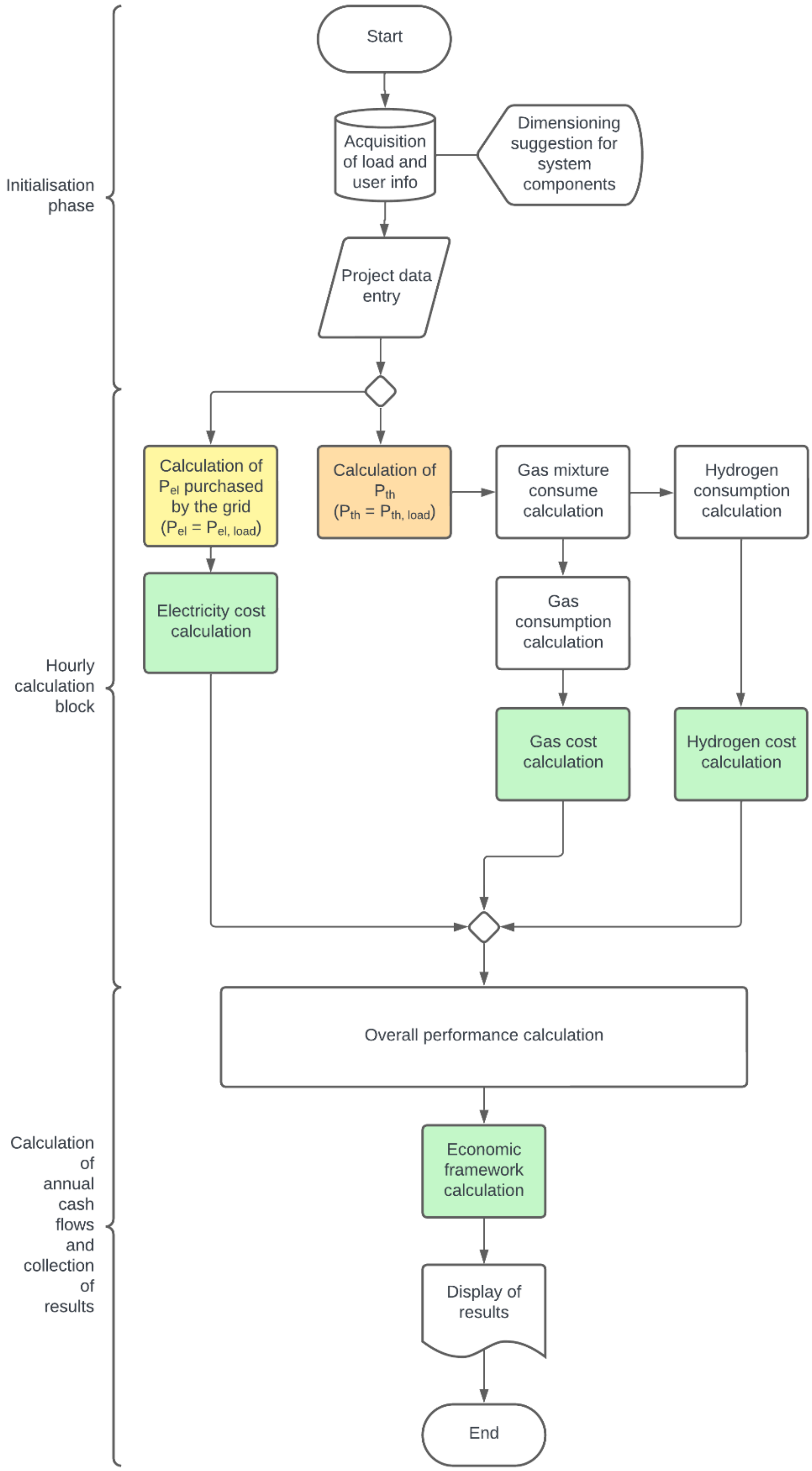


FIGURE 4-5: SCENARIO 3, SIMULATOR ALGORITHM

In this third scenario, the steps followed are:

1. **Initialisation phase:** The designer inserts design variables into the control panel, including the option to include domestic hot water service and the percentage of hydrogen in the mix. Thermal storage and connection to the district heating network are not foreseen, counting on producing only the amount of thermal energy required by the user in real time. Once these data have been set, the simulator suggests the nominal power value for the boiler. The designer completes the initialisation with the choice of generator's power.
By entering the volume fraction of hydrogen in a mixture with natural gas, the simulator independently calculates the calorific value of the mixture and the contribution of each component to the calorific value of the mixture.
The calorific value of the mixture is calculated as:

$$LHV_{mix,v} = LHV_{H2,v} * \varphi_{H2} + LHV_{gas,v} * (1 - \varphi_{H2})$$

Where:
$LHV_{mix,v}$: lower volumetric heating value of the mixture
$LHV_{H2,v}$: lower volumetric heating value of hydrogen
φ_{H2}: hydrogen volume fraction
$LHV_{gas,v}$: lower volumetric heating value of methane

The percentage heat input of each fuel, namely the percentage of energy produced by that specific gas contained in a unit of mixture, is calculated using the following two formulas:

$$LHV_{\%gas} = \frac{LHV_{gas,v} * (1 - \varphi_{H2})}{LHV_{mix,v}}$$

Where:
$LHV_{\%gas}$: percentage contribution of methane within the mixture
$LHV_{gas,v}$: lower volumetric heating value of methane
φ_{H2}: hydrogen volume fraction
$LHV_{mix,v}$: lower volumetric heating value of the mixture

$$LHV_{\%H2} = \frac{LHV_{H2,v} * \varphi_{H2}}{LHV_{mix,v}}$$

Where:
$LHV_{\%H2}$: percentage contribution of hydrogen within the mixture
$LHV_{H2,v}$: lower volumetric heating value of hydrogen
φ_{H2}: hydrogen volume fraction
$LHV_{mix,v}$: lower volumetric heating value of the mixture

The values of the contributions of each component of the mixture are not used directly to simulate the scenario but can be useful to quantify the impact of each fuel on overall energy production.
Once this initial data has been set, the simulator proceeds with the hourly calculation of the generation plant's performance performing the following steps for each hour.

2. **Calculation of thermal power and energy generated:** The heat output generated by the boiler, as mentioned, is always equal to the power required by the user, as is the case for any traditional boiler. This value is therefore equivalent to:

$$P_{th} = P_{th,load}$$

Where:
P_{th}: generated thermal power
$P_{th,load}$: thermal power required by the consumer

The energy produced is obtained by multiplying the power by one hour.

$$E_{boiler} = P_{th} * 1h$$

Where:
E_{boiler}: thermal energy produced by the boiler
P_{th}: generated thermal power

Then the resource consumption is calculated.

3. **Calculation of hydrogen consumption:** Given the power output and the efficiency of the boiler, the volume of mixture consumed can be calculated. From this volume is possible to calculate both hydrogen and natural gas consumption, defined the volume fractions during the initialisation phase. The formula followed is:

$$V_{H2} = \frac{E_{boiler}}{\eta_{boiler} * LHV_{mix,v}} * \varphi_{H2}$$

Where:
V_{H2}: volume of hydrogen consumed
E_{boiler}: thermal energy produced by the boiler
η_{boiler}: boiler thermal efficiency
$LHV_{mix,v}$: lower volumetric heating value of the mixture
φ_{H2}: hydrogen volume fraction

4. **Calculation of gas consumption:** Similarly, the amount of gas burnt is calculated. The formula followed is:

$$V_{gas} = \frac{E_{boiler}}{\eta_{boiler} * LHV_{mix,v}} * (1 - \varphi_{H2})$$

Where:

V_{gas}: volume of gas consumed
E_{boiler}: thermal energy produced by the boiler
η_{boiler}: boiler thermal efficiency
$LHV_{mix,v}$: lower volumetric heating value of the mixture
φ_{H2}: hydrogen volume fraction

A cost is then calculated for each resource on an hourly basis.

5. **Calculation of electricity costs**: The electricity consumed in this scenario comes exclusively from the grid, so the cost for this consumer is the same as in the actual state and is calculated as:

$$c_{el,h} = P_{el,load} * 1h * c_{el,buy}$$

Where:

$c_{el,h}$: cost of electricity in the calculated hour
$P_{el,load}$: electrical power required by the consumer
$c_{el,buy}$: electricity purchase cost in the hourly billing band

6. **Calculation of gas cost:** Gas expenditure is calculated as:

$$c_{th,h} = V_{gas} * LHV_{gas,v} * c_{gas,buy}$$

Where:

$c_{th,h}$: gas purchase cost in the calculated hour
V_{gas}: volume of gas consumed
$LHV_{gas,v}$: lower volumetric heating value of methane
$c_{gas,buy}$: gas purchase cost

7. **Hydrogen cost calculation:** Hydrogen expenditure is then calculated by knowing the purchase price and the volume consumed.

$$c_{H2,h} = V_{H2} * c_{H2,buy}$$

Where:

$c_{H2,h}$: cost of the hydrogen resource in the calculated hour
V_{H2}: volume of hydrogen consumed

$c_{H2,buy}$: hydrogen purchase price

8. **Calculation of the total cost of resources:** Finally, the costs for each resource are added up to calculate the overall economic balance for the hour. In formula:

$$c_{tot,h} = c_{el,h} + c_{th,h} + c_{H2,h}$$

Where:

$c_{tot,h}$: total cost of resources in the calculated hour
$c_{el,h}$: electricity cost in the calculated hour
$c_{th,h}$: gas purchase cost in the calculated hour
$c_{H2,h}$: cost of the hydrogen resource in the calculated hour

4.2.3 The storage system

The installation of a thermal storage system is investigated.
Numerous thermal storage options are available on the market, differing mainly in volume and thermal insulation of the tank. In most residential installations, a simple and economical technology based on sensible heat storage through energy exchange with a water tank is used.
Depending on the technical specifications of the model chosen, there are differences in the conservation of heat inside the storage tank. This can affect both heat loss to the outside and the internal heat stratification, which can occur in different ways depending on the internal conformation of the tank.
The simulator is programmed to perform a simplified simulation of thermal storage performance throughout the year.
During the initialisation phase, the designer may indicate the presence of a thermal storage and its size. Once the capacity has been defined, the simulator determines the specifications and performance that that storage tank could have according to the methodology outlined below.

1. **Determining the internal geometry of the storage tank**: The first parameters calculated are those relating to the geometry of the storage tank. Research into the models available on the market has shown that in most cases the tank of a thermal storage tank has a shape approximating to a cylinder, with a ratio of its height to its radius varying from approximately 2.5 for the smallest tanks to over 4 for the largest ones. Assuming an average value of this ratio of 3.5 and choosing the volume of the storage tank, the values of radius and height are calculated by solving:

$$\begin{cases} V = A_b * \mathrm{h} = \pi * r^2 * \mathrm{h} \\ \dfrac{h}{r} = 3.5 \end{cases}$$

Where:

V: internal volume of thermal storage

A_b: storage internal base area

h: storage internal height

r: storage inner radius

2. **Determining the thermal resistance of the storage tank**: The thickness of the storage tank walls and its thermal performance are simulated considering only the thermal insulation layer. This assumptions is motivated considering the contribution of the structural envelope as negligible. It is assumed the presence of a thickness of 20 cm of expanded polyurethane with high thermal insulation, having a conductivity of 0.028 W/(m*K), coherently with the specifications of manufacturer Cordivari [19].
   Given the thickness values and material specifications, the thermal resistance of the tank side walls can be calculated as:

$$R_{cyl,side} = \frac{ln\left({}^{r_{ext}}/_{r_{int}}\right)}{2\pi h\lambda}$$

   Where:

   $R_{cyl,side}$: conductive thermal resistance of the storage side wall

   r_{ext}: storage outer radius

   r_{int}: storage inner radius

   h: storage height

   λ: thermal conductivity of the insulation

   The thermal resistance of the horizontal tank walls is calculated as:

$$R_{cyl,b} = \frac{s}{A_b\lambda}$$

   Where:

   $R_{cyl,b}$: conductive thermal resistance of the storage horizontal wall

   s: storage thickness

   A_b: storage internal base area

   λ: thermal conductivity of the insulation

   The convective heat transfer coefficients are assumed to be 500 W/(m^2*K) for internal convective exchange with water and 25 W/(m^2*K) for external convective exchange with air, respectively.

3. **Simplified calculation of stratification**: Heat stratification inside a tank is a complex phenomenon that must be taken into account for a correct calculation of heat losses to the outside.

This phenomenon, although occurring spontaneously due to the temperature gradient, can be strongly influenced by the layout of the storage. It is not infrequent, in fact, that some more sophisticated storage systems favour this phenomenon with their internal layout in order to dispose of the greatest amount of available heat as quickly and efficiently as possible. In a simpler system, on the other hand, stratification only occurs due to the non-uniform temperature of the water mass inside the tank. A precise analysis of stratification should take into account the specifics of each storage tank on a case-by-case basis. For the sake of simplicity, the simualtor is programmed to consider a stratification of the system under consideration into three zones of homogeneous temperature. The height and temperature values of these zones are assumed by analogy with what was obtained experimentally in the research of Deng et Al. published in [20], represented in **figure 4-6**.

In that paper the authors present an example of a temperature profile related to the height of a reservoir and the dimensionless temperature, from which a series of parameters can be derived. With a simple elaboration, values of height and temperature can be extrapolated and consequently the amount of heat present in each zone can be calculated. What is calculated is shown in the **table 4-1**.

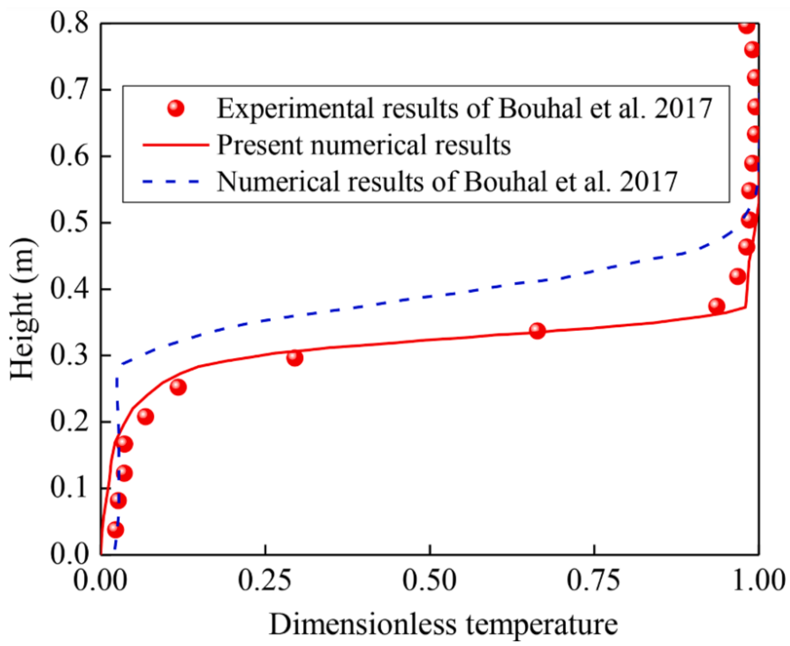


FIGURE 4-6: EXAMPLE OF LAYERING. IMAGE FROM [20] OWNED BY DENG ET AL.

TABLE 4-1: STRATIFICATION PARAMETERS ADOPTED

	Height (percentage of total height):	**Temperature (percentage of maximum temperature):**	**Percentage of heat stored**
Cold zone:	38%	6%	4%
Thermocline zone:	6%	51%	5.2%
Hot zone:	56%	95%	90.8%

4. **Hourly calculation of zonal temperature and losses into the storage:** Given the previously calculated values, the heat from the storage is considered to be distributed in each zone according to the relative heat storage percentages, until the maximum temperature in any zone is reached. When the energy stored in the tank causes the zone temperature to rise to its maximum value (equal to the maximum temperature receivable by the cell cooling circuit), the excess energy is stored in the lower zone, until the system is fully charged.
During the simulation, the temperature of each zone is calculated according to the amount of energy in it. Consequently, the losses of the walls in contact with each zone are calculated. The sum of the contributions of the entire dispersing surface corresponds to the value of the storage losses.

Assuming a temperature of 60 °C for the hot fluid from the fuel cell cooling circuit, the maximum attainable temperature in the storage tank can be up to 55 °C. The tap water temperature from the aqueduct is assumed to be 15 °C. The temperature difference of the storage tank to the tap water is consequently assumed to be 40 °C, which is equivalent to the maximum temperature difference attainable during a withdrawal of heat from the storage tank.
The temperature values assumed for the thermal storage are shown in **table 4-2**.

TABLE 4-2: THERMAL STORAGE SPECIFICATIONS

Maximum storage temperature	55	°C	**Tap water temperature (aqueduct)**	15	°C
Thermal increase in storage	40	°C	**Water specific heat**	0.001162	kWh/(kg * K)

Using these values, it is possible to estimate the thermal capacity of a storage tank as a function of its volume. **Table 4-3** shows some storage tank sizes on the market, found in [19], with relative thermal capacity under the conditions discussed.

TABLE 4-3: VALUES OF HEAT CAPACITY FOR DIFFERENT STORAGE VALUES AT DESCRIBED CONDITIONS

Storage system volume [L]:	Storage heat capacity[kWh]:
200	9.30
300	13.94
500	23.24
600	27.89
750	34.86
800	37.18
1000	46.48
1250	58.10
1500	69.72
2000	92.96
2500	116.20
3000	139.44
4000	185.92
4500	209.16
5000	232.40
6000	278.88
8000	371.84
10000	464.80
12000	557.76
20000	929.60

4.3 Economic analysis

The economic analysis is conducted by the simulator after calculating the building's energy metrics. Each scenario is calculated considering the condominium as an investor who adopts the described systems to generate the energy it needs. The first step in the economic calculation is the calculation of the initial investment cost, which takes into account the cost incurred in purchasing the devices adopted in the scenario. This is followed by the calculation of the operation costs for the aforementioned devices, and any component replacement costs. Each year, the amounts of accessible deductions and incentives are then considered as a positive cash flow. The costs of each energy resource are first calculated on an annual basis as described in the previous chapters, then included as a cost or income in the cash flow. Similarly, the cost of current-state utility resources (purchase of electricity and gas from the grid) is calculated and reported as a saving. Finally, the sum of all cash flows is calculated and then discounted at an interest rate of 5%. The investment, calculated over a 20-year period, is then evaluated using the indicators of net present value (NPV), payback time (PBT) and internal rate of return (IRR).

Each of these steps is described in detail below.

4.3.1 Economic parameters

The following parameters have been adopted for the calculation of the economic framework.

4.3.1.1 Buying and selling of energy resources

The cost of electricity purchased by the grid is calculated taking into account the PUN of April 2023 indicated by *Gestore Mercati Energetici* (*GME*) in [21] and the spread for the energy component. Electricity PUN is different for each billing band and is equal to, respectively, 0.13555 €/kWh for F1, 0,15205 €/kWh for F2 and 0,1264 €/kWh for F3. The spread is assumed equal to 0.002 €/kWh. Sales price of electricity is assumed equal to the PUN alone for the same period.

For thermal energy, the gas market price of April 2023 is adopted as purchase cost, which is equal to 0.148391 €/kWh. The sale cost is calculated as the difference between purchase cost and the spread, so it is equal to 0.146391 €/kWh.

Sales revenues are taxed at a rate of 23%.

The cost of hydrogen is assumed to be 7 €/kg for the first year of operation with an annual decrement of 0.25 €/kg until the minimum threshold of 2 €/kg is reached. This choice is motivated by a more conservative interpretation of the scenarios proposed by Bloomberg in [5].

4.3.1.2 Initial costs of investment

The adopted capex of the fuel cell is approximated by the function:

$$capex_{FC} = 1076.2 * \mathrm{P}_{nom} + 16780$$

Where:

$capex_{FC}$: cost of the fuel cell, expressed in €

P_{nom}: rated power of the fuel cell, expressed in kW

This function is a linear approximation of the market price models with power similar to those employed in the case study obtained through market quotations provided by fuel cell manufacturers.

Similarly, the purchase price boilers and thermal storages was found by researching the models available on market.

The purchase cost of heat exchangers is provided by the 2023 regional price list [22].

The cost of all ancillary works (such as design, installation, transport and others) is quantified as the 36% of the related component's purchase cost.

Incentives on components' cost are taken into account and described later.

4.3.1.3 Operation cost and components duration

Operation cost and duration of boiler, thermal storage and heat exchanger are sourced from standard UNI EN 15459-1:2018 [23]. The costs are defined as a percentage of components initial cost and are, respectively, 2% for the boiler and 1% for the heat exchanger and the thermal storage. The fuel cell's cost is set to 4% of initial cost.

The lifespan of all the component is set to 20 years.

4.3.1.4 Costs of replacement

As mentioned in a previous chapter, a replacement of fuel cell's stack during the generator's lifespan can be necessary one or more time.
The replacement cost of the stack is assumed equal to 27% of the fuel cell's cost, as reported in [12]. The stack life is assumed to be 50000 operation hour, in accordance with what was discussed in the previous chapter. The price of this component is expected to decrease significantly in the near future, to a minimum price of 63 €/kW in 2030 according to [24]. A linear annual reduction in the cost of the stack of 8% is therefore assumed.
To the replacement cost is added the same surcharge of 36% of the component cost.

4.3.2 Incentives and deductions

Sustainable energy production plants fuelled by renewable energy sources can benefit from different incentive options, aligned with the energy refurbishment policy embraced at both national and European level. Below is quantified the impact that some of the main incentives may have on the economic performance of the scenarios previously discussed.

4.3.2.1 Deductions on initial cost of investment

As regards components' purchase, two incentives are taken into account. Fuel cell can be eligible for the *microgenerator bonus*, which refund 65% of its purchase cost with constant annual instalments over ten years. The boiler's buying can benefit from *Ecobonus*, which offers the same advantages and modes of microgenerator bonus. Where present, the thermal storage is eligible for the incentives of its system's generator and is discounted in the same way.
Therefore, the first ten years of operation have a positive income from these incentives.

4.3.2.2 Incentives for green energy production

To date, a Ministerial Decree draft of the Italian *Ministero dell'Ambiente e della Sicurezza Energetica* (*MASE*) is in discussion [25]. The Decree's aim is the transposition of European Renewable Energy Directive and contains incentives for REC and self-consumption groups.
For plants producing electricity from renewable sources with a nominal capacity less than 1 MW, this draft anticipates an incentive tariff regulated on the quantity of electricity generated in a sustainable way.
This tariff is calculated as:

$$TIP = 80 + \max(0; 180 - Pz)$$

Where:
TIP: premium incentive tariff, calculated in €/MWh produced
Pz: hourly zonal electricity price

The maximum value of TIP is set equal to 120 €/MWh.
In accordance with these incentives, it is possible to estimate a minimum incentive for the energy produced by the fuel cell of 0.106 €/kWh, which multiplied by the energy produced allows the calculation of the annual premium.

4.3.2.3 Tradable securities: white certificates

Another kind of incentives are tradable securities.
White certificates are tradable certificates issued by the GSE certifying the achievement of savings in energy end-use through energy efficiency measures and projects. One certificate is issued for saving of one tonne of oil equivalent (toe) and are paid out for a period of 15 years from the commissioning of the installation. The conversion factor from toe to kWh is provided by ARERA [26] and is:

$$1\ kWh = \ 0.000187\ toe$$

These certificates constitute an incentive that cannot be combined with other forms of incentives on the sale of energy, and therefore compete with the incentives of the mentioned Decree draft. In the economic framework the value of this incentive is calculated and confronted with previous mentioned incentives on energy sell to determine which is the best option to adopt for the case study.
Table 4-4 resumes all the economic parameters mentioned above.

TABLE 4-4: ECONOMIC PARAMETERS

<table>
<tr><th colspan="4">Buying and selling energy resources:</th></tr>
<tr><td colspan="2">Gas purchase price</td><td>0.148391</td><td>€/kWh</td></tr>
<tr><td colspan="2">Selling price of thermal energy (district heating)</td><td>0.146391</td><td>€/kWh</td></tr>
<tr><td rowspan="3">Electricity purchase price (per band):</td><td>F1</td><td>0.13755</td><td>€/kWh</td></tr>
<tr><td>F2</td><td>0.15405</td><td>€/kWh</td></tr>
<tr><td>F3</td><td>0.1284</td><td>€/kWh</td></tr>
<tr><td rowspan="3">Electricity selling price (per band):</td><td>F1</td><td>0.13555</td><td>€/kWh</td></tr>
<tr><td>F2</td><td>0.15205</td><td>€/kWh</td></tr>
<tr><td>F3</td><td>0.1264</td><td>€/kWh</td></tr>
<tr><td colspan="2">Taxation (IRAP) on energy sales:</td><td>23%</td><td>-</td></tr>
<tr><td colspan="2">Cost of purchasing green hydrogen:</td><td>7</td><td>€/kg</td></tr>
<tr><td colspan="2">Estimated change in the cost of hydrogen:</td><td>-0.25</td><td>€/(kg*y)</td></tr>
<tr><td colspan="2">Minimum hydrogen cost:</td><td>2</td><td>€/kg</td></tr>
<tr><th colspan="4">Capex:</th></tr>
<tr><td>FC:</td><td>FC cost formula (‘x’ is the rated power, expressed in kW):</td><td>1076.2*x + 16780</td><td>€/kW</td></tr>
<tr><td colspan="2">Boiler:</td><td>Market price</td><td>€</td></tr>
</table>

Heat Exchanger:	Counterflow heat exchanger with copper tube bundle (complete with flanged bottom, connections for coil, cold and hot water, etc.).	19.76	€/kW
Thermal storage		Market price	€
Estimated ancillary costs (labour, technical design and asseveration costs, etc.)		36%	% component cost
Opex:			
Fuel cell		4%	% of capex
Heat exchanger		1%	% of capex
Boiler		2%	% of capex
Thermal Storage		1%	% of capex
Replacement:			
FC:	Fuel cell stack	27%	% of capex
	Stack life	50000	h
	Annual replacement cost reduction	8%	% of replacement cost
	Minimum replacement cost (2030)	63	€/kW
Financial factors:			
Discount rate:		5.00%	-
Deductions:	Fuel cell, boiler and joint components	65%	% of capex (in 10 years)
	Years of deduction:	10	years
	Annual deduction payment:	6.5%	% of capex, each year

5 Case Study

5.1 The case study building

The residential building of this paper's case study is the one used as case study in «Approfondimento teorico del modello di calcolo orario semplificato (UNI EN ISO 52016-1:2018) e applicazione al settore residenziale», by Corrado et Al. [18], of which the hourly heat load profile for the one-year period was made available by the author Corrado.
The main features of the building are summarised in **table 5-1**, while the building is shown in **figure 5-1**.

TABLE 5-1: CHARACTERISTICS OF THE CASE STUDY BUILDING [18]

Site:	Rome (Italy) – Climate zone D	**Gross heated volume:**	5280 m^3
Year of construction:	1926	**Net heated surface area:**	1091 m^2
Number of plans (subject of analysis):	6	**Dispersing envelope surface:**	1958 m^2
Housing units present:	18	**Form ratio:**	0.37 m^{-1}

FIGURE 5-1: THE CASE STUDY BUILDING . PROSPECTS SUD-EST (A – VIALE DELLO SCALO SAN LORENZO), NORD-EST (B – VIA DEI RETI) AND NORD OVEST (C – VIA DEGLI ENOTRI). IMAGE FROM [18]

The central heating service of this building as it stands is provided by a cast-iron floor-standing thermal generator with an atmospheric suction air burner with a nominal useful heat output of 152.5 kW and useful heat output at nominal output of 0.904 [18].

5.2 Hypotheses adopted

For the scenarios applied in this case study, the following assumptions were adopted.

5.2.1 Hydrogen supply through the grid

Having excluded the case where a private supply is possible for the user under study due to technical constraints imposed by the urban context, it is assumed that hydrogen is supplied through a public distribution network as is the case for natural gas. This assumption will be fulfilled for mass consumption in Europe upon completion of hydrogen distribution projects as part of a broader plan on green hydrogen production. By 2040, it is estimated that this distribution network could cover an extension of 39700 km along 21 European countries [27]. Before this date, the availability of hydrogen from the grid will reasonably be limited to users not far from mass production sites or to energy communities that should equip themselves with their own production plant through electrolysis.

5.2.2 Hydrogen price

As mentioned above, the price of green hydrogen is expected to drop significantly in the coming years. For the purpose of the case study, it has been assumed that this resource can be purchased in the year at an initial price (i.e. referring to year 1 of the plant's commissioning) of 7 €/kg, which is currently too low in the event that a different refuelling method than the one discussed is used.
It is also chosen to assume a constant price decrease during the years of operation of 0.25€/year, in accordance with the forecasts of [5].

5.2.3 Ideal fuel cell responsivity

An ideal responsivity of the fuel cell is assumed.

5.2.4 Presence of a district heating network

Although the simulator is designed to calculate it as described in the previous chapters the presence of a thermal storage plant, for the case study we choose to assume the presence of a district heating network where the excess heat produced by the fuel cell is fed. From such a network it is imagined that no heat can be withdrawn, simulating a scenario of an energy community where it is the case study building that generates thermal energy for neighbouring users. The performance of the storage plant will be examined separately in a later chapter.

6 Results and discussion

6.1 Calculation of heat and electricity requirements

A total heating energy requirement of 67158 kWh per year is calculated as a sum of each hourly demand for the year of study.
This consumption, in relation to the number of flats in the condominium, is 3731 kWh per flat per year.
The required peak heat output for the heating service is 47 kW.

The total electricity consumption is estimated at 74117 kWh per year. This consumption, in relation to the residential units, is 4118 kWh per year per flat, and can be assumed similar to the electricity consumption of a building with similar characteristics.
The required peak electrical power is 38.4 kW.

A total thermal energy demand for DHW of 30534 kWh per year is calculated. This consumption, in relation to the number of flats in the condominium, is 1696 kWh per flat per year.
The peak heat output required for the DHW service is 8.4 kW.
The total required peak heat output for heating and DHW services is estimated at 54 kW. This value is the correct one to dimension the thermal generator.

6.2 Dimensioning of components

The dimensioning of components is part of the preliminary phase of the calculation process and follows different criteria depending on the scenario under consideration. Each scenario is discussed in more detail below.

6.2.1 Scenario 1: load-following fuel cell

The simulator calculates from the utility's electrical load what the required peak power is on an annual basis and indicates that value as the suggested power for the fuel cell, in accordance with the assumption that it can fully meet the electrical demand. For the current scenario, the value is 38.4 kW.

Once the power of the cell has been chosen, the simulator can carry out an initial simulation considering an ideal storage system (infinite heat capacity, no losses), and calculate the theoretical maximum quantity of energy that can be stored in it, considering the hourly heat production of the cell and the heat load of the user during the same period. In this way, it proposes a useful figure for choosing the size of the storage unit. For very small values of the theoretical maximum capacity, it will be necessary to opt for a small storage tank, while for larger values it will be more convenient to have a larger storage or a district heating network. The best dimensioning from an economic point of view can be done later by means of an economic analysis. The value for the choice in this case is 8415 kWh.

Next, the maximum thermal power exchanged with the heat storage (or district heating) is calculated, which is useful for dimensioning the heat exchanger. This power is 28.78 kW for the thermal power to the storage or district heating and 40.45 kW for the thermal power withdrawn from the storage.
Finally, considering the contribution of the thermal generation of the cell and the value of the loads, the minimum power the boiler must be able to supply to independently satisfy the thermal load not generated by the cell is calculated and suggested. According to these assumptions, the power required is 50.33 kW.

It follows that the size for the cell should be greater than or equal to 38.4 kW. A size equal to 40 kW was chosen, following a conservative approach.
The heat exchanger must have a minimum size of 35.8 kW, so 36 kW was chosen. The high value of storable thermal energy suggests not installing a thermal storage system on site, as this would not be sufficient to efficiently expend this energy. We proceed accordingly with the utility analysis assuming the presence of a connection to the district heating network.
The thermal generator in this scenario must not be less than 50.33 kW. Therefore, the current heat generator in the case study building, with an output of more than 150 kW, is considered suitable.

6.2.2 Scenario 2: constant-power fuel cell

In analogy to what was done in the first scenario, we continue with the dimensioning of this second case.
The electrical power supplied by the cell is dimensioned on the assumption of maintaining a constant value for the entire period of one year, chosen to produce the user's annual requirements in total. This value therefore corresponds to 8.46 kW.
The maximum thermal power deliverable to the storage or district heating is 3.53 kW. In the hypothesis of having an ideal storage tank the maximum power that can be withdrawn would reach the higher value of 14.7 kW. The dimensioning of this component is consequently dependent on the choice of storage system, the size of which also determines the amount of power that can be drawn.
The maximum theoretically storable energy in this scenario reaches a value of 212 kWh.
The maximum heat output required and not satisfied by heat from the cell in this scenario is 49.83 kW.

From these data, the sizing is concluded as follows.
The power rating of the fuel cell can in this case be determined by knowing the operating point of maximum efficiency, since in this scenario the power output does not fluctuate constantly to follow the load as in the previous scenario. The point with the best electrical efficiency, defined as the ratio of electrical power generated to hydrogen consumption, is at 27.5% of the power output.
The optimal cell size can then be calculated as:

$$P_{nom,el} = \frac{P_{mean,el}}{c_{eff.el.}} = \frac{8.46\ kW}{27.5\%} = 30.77\ kW$$

with

- $P_{nom,el}$: nominal electrical power of the cell
- $P_{mean,el}$: average electrical power to be delivered
- $c_{eff.el.}$: ratio between power output and rated power at the point of maximum electrical efficiency, assumed to be 27.5%.

It is consequently assumed that an acceptable value for the rated power of the cell could be 30 kW, being a size available on the market close to the most efficient one.
The excess heat generated by the cell also causes in this scenario the need to resort to district heating to utilise this energy. The heat exchanger is therefore sized at 4 kW, assuming that it only needs to drawing heat from the cell cooling circuit. On the other hand, the power required from the boiler is about 50 kW and does not require the replacement of the heat generator in the case study building.

6.2.3 Scenario 3: hydrogen boiler

In this scenario, the required thermal energy is produced by a single generator, sized to cope alone with the peak load in the year of the case study. The absence of collateral heat generation to other processes makes the presence of heat recovery equipment of any kind unnecessary. The only component to be considered is therefore the H2-ready boiler. Such a boiler must be sized to meet the heat load of the utility by itself. Consequently, it must have at least an output equal to the maximum power required simultaneously by the heating and domestic hot water services. This power value is 53.4 kW.

For the case study, a thermal generation capacity of 60 kW was chosen, to follow a conservative approach motivated in part by the limited availability of these devices on the market, which are currently less widespread than traditional boilers, of which wider ranges of capacities are available.
In this scenario, electricity is assumed to be purchased from the grid as it is in the current scenario.

The table 6-1 resumes the dimensioning of all scenarios.

TABLE 6-1: VALUES FOR DIMENSIONING AND ADOPTED DIMENSIONS FOR EACH SCENARIO

Scenario 1			
Maximum annual values	Required peak electrical power	38,4	kW
	Maximum thermal power deliverable to storage/district heating	28,78	kW
	Maximum thermal power withdrawable from the storage (ideal storage, theoretical maximum)	40,45	kW
	Maximum storable energy (ideal value)	8415	kWh

	Maximum thermal power produced by boiler (cell present, thermal storage absent)	50,33	kW
Adopted dimensions	Nominal (electrical) power fuel cell	40	kW
	Heat recovery exchanger size	36	kW
	Thermal storage	Absent	
	Thermal generator power (actual state)	152,7	kW
Scenario 2			
Maximum annual values	Average annual electrical power generated (constant value)	8,46	kW
	Maximum thermal power deliverable to storage/district heating	3,5	kW
	Maximum thermal power withdrawable from the storage (ideal storage, theoretical)	14,7	kW
	Maximum storable thermal energy (ideal value)	212	kWh
	Maximum thermal power produced by boiler (cell present, thermal storage absent)	49,83	kW
Adopted dimensions	Nominal (electrical) power fuel cell	30	kW
	Heat recovery exchanger size	4	kW
	Thermal storage	Not present	
	Thermal generator power (actual state)	152,7	kW
Scenario 3			
Maximum annual values	Heat output at boiler load (heating and DHW)	53,4	kW
Adopted dimensions	Boiler rated power	60	kW

6.3 Annual tally results

This chapter shows the energy results for each scenario, calculated according to the dimensioning described above.

For scenarios 1 and 2, it is possible to observe through graphs what the electrical and thermal load is and, in the adjacent column, how this is met, month by month. These graphs are omitted for scenario 3, in which the loads coincide hour by hour with the power generated or purchased from the grid.

Negative values in the generation column represent surplus electricity or heat fed into the respective grid.

The data are then presented in tabular form.

6.3.1 Scenario 1: load-following fuel cell

Regarding the objectives of the scenario, the cell proves that it can supply the utility. A small amount of electricity is produced in excess compared to the demand. This is due to the minimum load hours, where less than the cut-off power is required. The difference,

represented with a negative value, can be fed into the grid and constitutes a small economic revenue.
This mode of operation of the cell therefore requires a way to spend the excess energy. Given the very low value of this energy in relation to the load, there is no need to install battery storage, as feeding it into the grid is sufficient. Any increase in the electrical load would not necessarily lead to the elimination of this surplus. A smaller cell, on the other hand, could bring the cut-off power below the minimum load threshold, but might not be sufficient to meet the peak load. **Figure 6-1** shows the electrical profile of the first scenario.

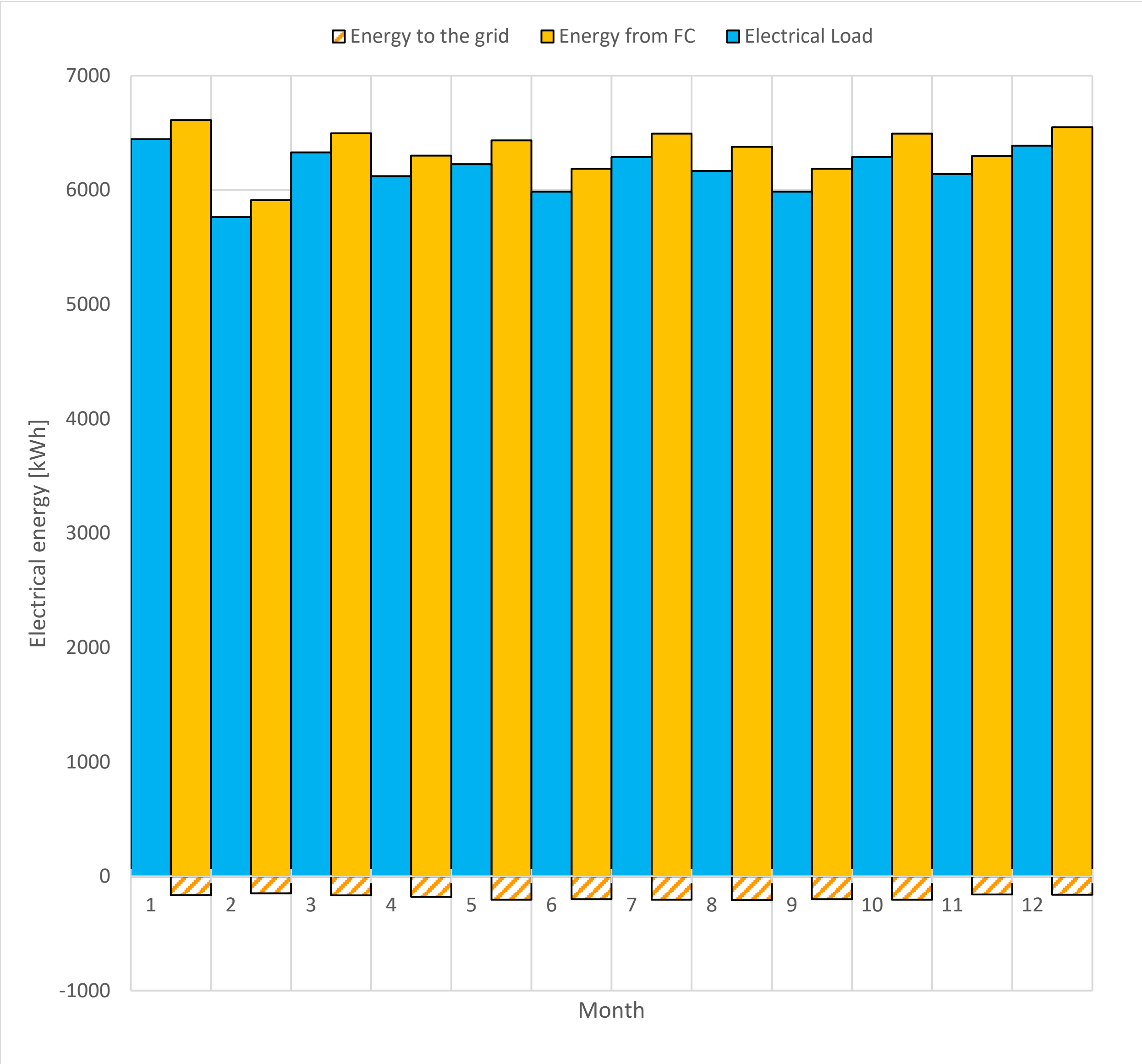


FIGURE 6-1: SCENARIO 1, LOAD AND GENERATION PROFILE (ELECTRICAL)

The thermal profile shows that the heat required by the utility is more than the heat produced by the fuel cell, except for the summer months, and a contribution from the boiler is required. On an annual basis, the cell produces about 45% of the heat required by the consumer, slightly less than that still required by the boiler.

In the winter months it can be seen that some of the heat is still fed into the district heating network, as it is produced asynchronously to the load.
The use of the cell as a heat generator is therefore most exploited during the winter months, in which the consumer can spend the heat produced. In the summer months, the heat could be used to supply air conditioning systems powered by hot fluids, as is case of the absorption chillers. **Figure 6-2** shows the thermal profile of the first scenario.

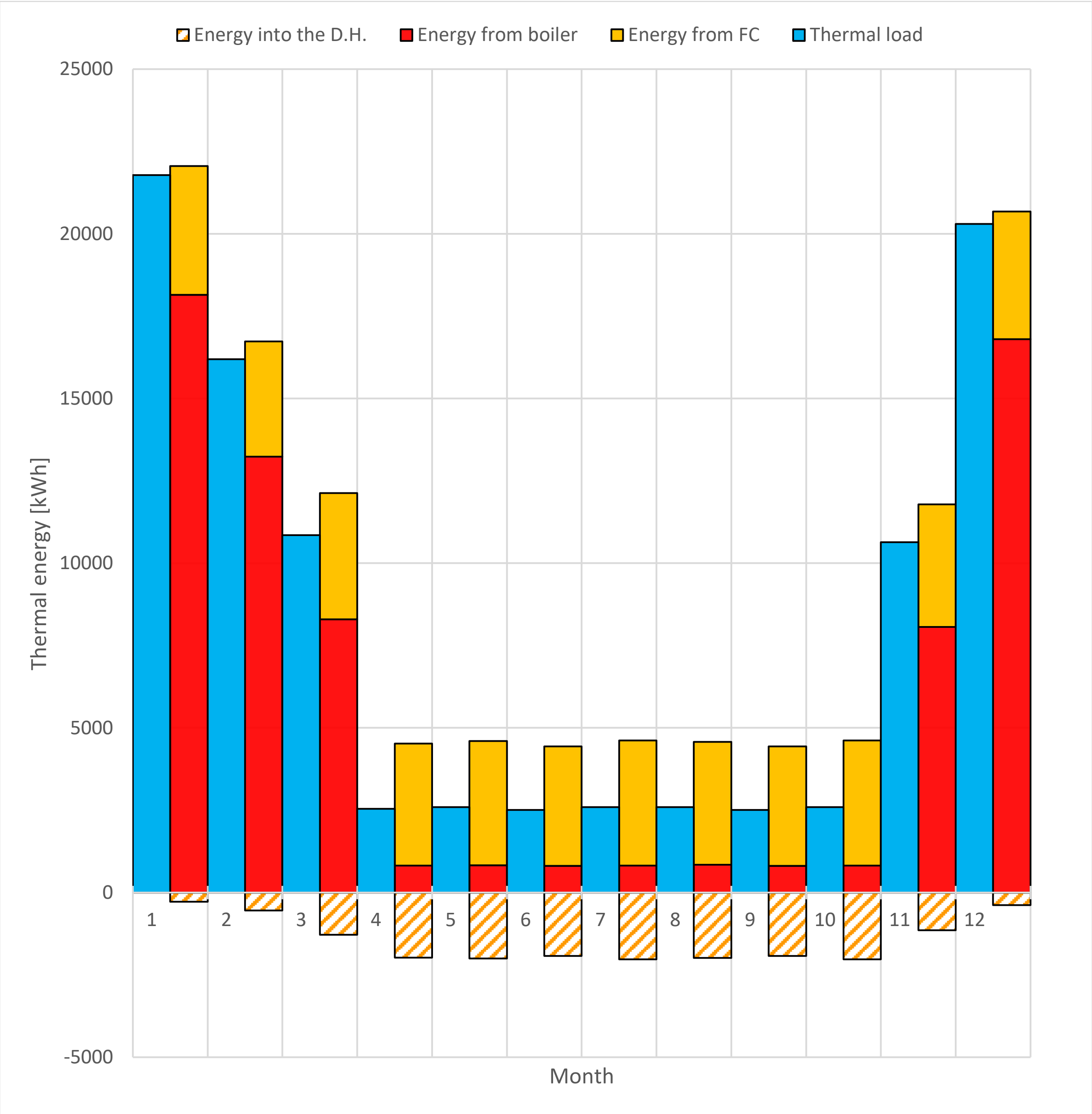


FIGURE 6-2: SCENARIO 1, LOAD AND THERMAL GENERATION PROFILE

Table 6-1 shows the annual tally results in details.

TABLE 6-1: SCENARIO 1, ANNUAL TALLY RESULTS

Month	$E_{el,load}$ [kWh]	$E_{el,FC}$ [kWh]	$E_{el,grid}$ [kWh]	Max $E_{el,FC}$ [kWh]	$E_{th,load}$ [kWh]	$E_{th,FC}$ [kWh]	Max $E_{residual}$ [kWh]	Max $E_{exchanged}$ [kWh]
1	6445	6610	-165	38.40	21781	3908	49.84	20.07
2	5761	5911	-150	38.40	16191	3494	50.33	27.24
3	6328	6495	-168	38.40	10850	3838	46.09	28.78
4	6121	6301	-180	38.40	2546	3706	8.02	28.78
5	6227	6434	-207	38.00	2593	3766	5.51	27.81
6	5984	6186	-202	38.00	2510	3620	5.51	27.81
7	6287	6492	-205	38.00	2593	3800	5.51	27.81
8	6168	6376	-209	38.00	2593	3732	5.51	27.81
9	5984	6186	-202	38.00	2510	3620	5.51	27.81
10	6287	6492	-205	38.00	2593	3800	5.51	27.81
11	6139	6298	-158	38.40	10635	3722	40.45	28.78
12	6386	6549	-163	38.40	20296	3871	49.74	23.63
Total / Max.:	**74117**	**76331**	**-2213**	**38.40**	**97692**	**44878**	**50.33**	**28.78**

Month	$E_{D.H.}$ [kWh]	E_{boiler} [kWh]	Max E_{boiler} [kWh]	V_{H2} [Nm^3]	c_{el} [€]	c_{th} [€]	c_{H2} [€]	c_{tot} [€]
1	274	18148	49.84	4395	-17	2653	2765	5401
2	541	13239	50.33	3934	-15	1885	2475	4345
3	1281	8293	46.09	4325	-17	1043	2721	3747
4	1980	820	8.02	4187	-18	-168	2635	2448
5	2004	831	5.51	4273	-21	-170	2688	2497
6	1924	814	5.51	4110	-21	-161	2586	2404
7	2026	819	5.51	4308	-21	-175	2710	2514
8	1983	844	5.51	4238	-21	-165	2666	2480
9	1924	814	5.51	4110	-21	-161	2586	2404
10	2026	819	5.51	4308	-21	-175	2710	2514
11	1147	8061	40.45	4193	-16	1028	2638	3650
12	380	16804	49.74	4358	-17	2438	2742	5163
Total / Max.:	**17491**	**70305**	**50.33**	**50739**	**-226**	**7872**	**31923**	**39569**

6.3.2 Scenario 2: constant-power fuel cell

In the second scenario, we can observe an adherence of electrical generation to almost full load on a monthly basis. The differences between the two profiles are due to the fact that the load demand is not perfectly constant over time but can be approximated to periodic over a time span of the order of a month.

Also in this scenario it is necessary to use the grid as a virtual store of electricity, the generation of which is asynchronous to the load. The amount of energy exchanged with the grid shown in the graph is the total monthly amount, i.e. it is the sum of all deposits and withdrawals. An analysis with a shorter time period shows that the exchange of energy is, on the other hand, continuous, since generation is constant and equal to an averagely low value with respect to load. **Figure 6-3** shows the electrical profile of the second scenario.

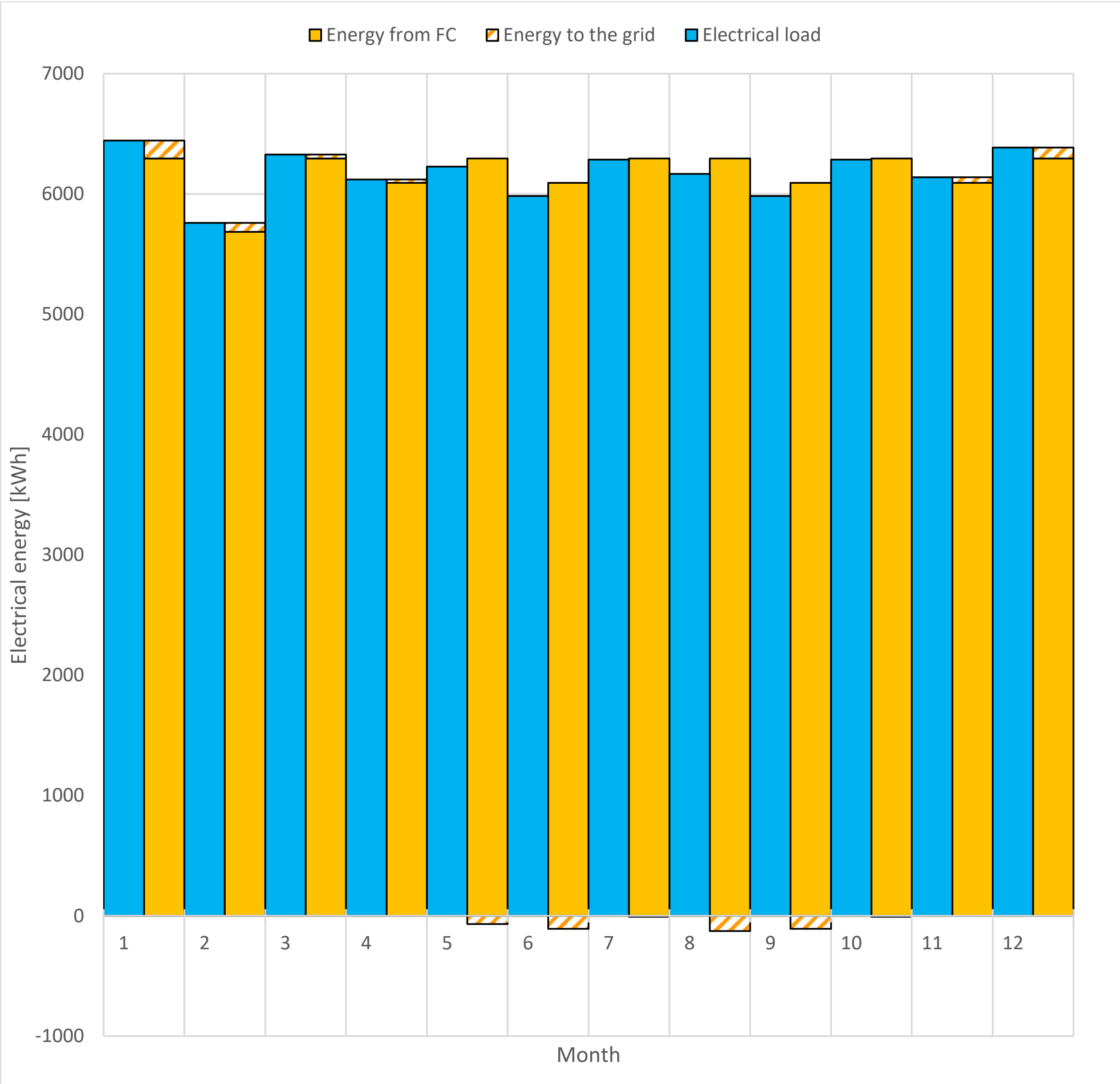


FIGURE 6-3:SCENARIO 2, LOAD AND ELECTRICAL GENERATION PROFILE

From **Figure 6-4**, we can see that the thermal energy production of the fuel cell is essentially constant over time, and represents a basic input during winter periods, in which it is unable to meet the heat demand on its own.
In the summer months, on the other hand, heat production is greater than demand, but nevertheless a contribution from the boiler is required to meet the required output at certain times. The summer use of the boiler is therefore limited, but not absent, and part of the thermal energy must still be fed into the district heating network.
The use of thermal energy in the supply of cooling systems can also be considered here, although the summer surplus is smaller and therefore less convenient.

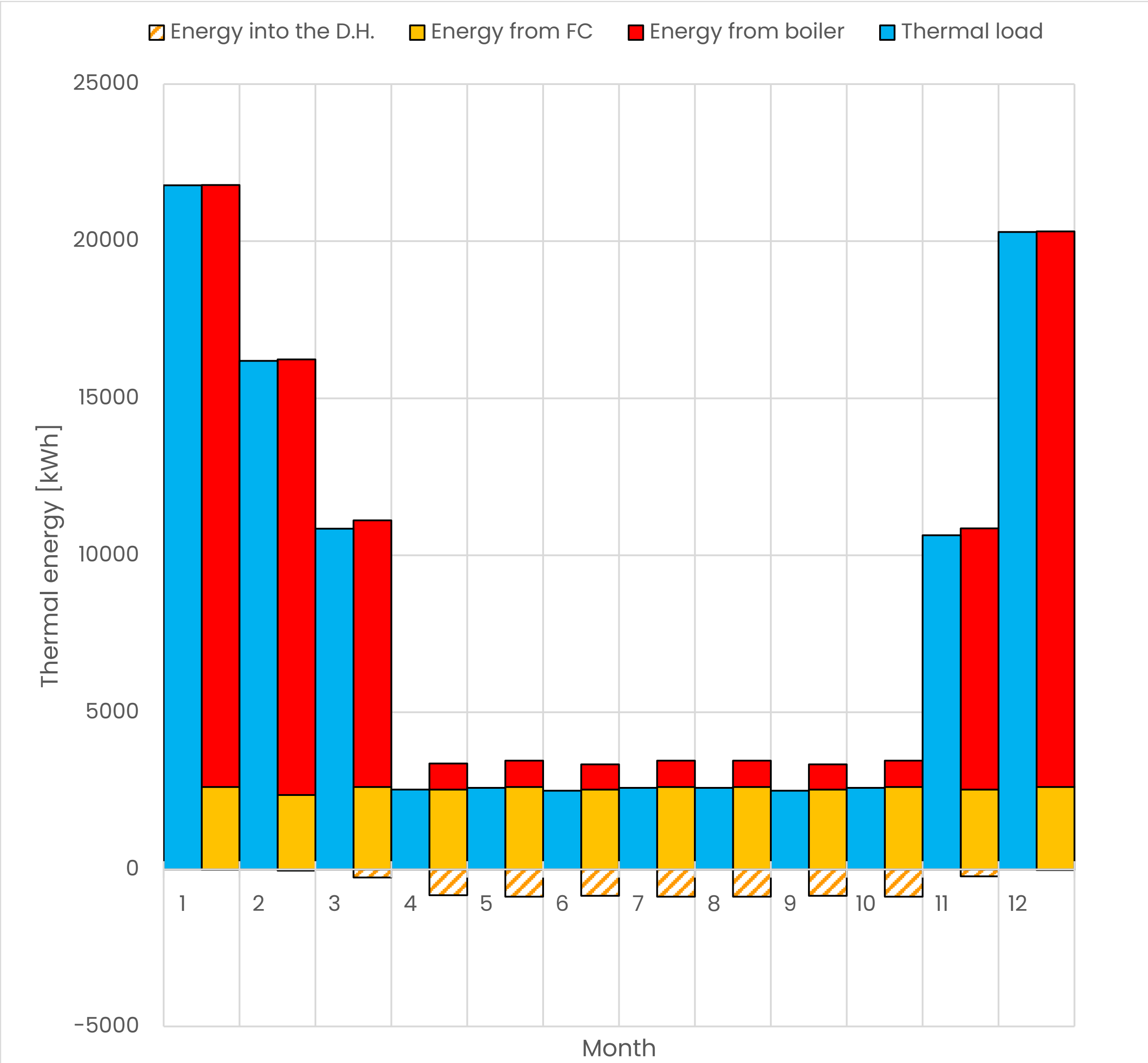


FIGURE 6-4: SCENARIO 2, LOAD AND THERMAL GENERATION PROFILE

Table 6-2 reports the annual tally results in details.

Table 6-2: Scenario 2, annual tally results

Month	$E_{el,load}$ [kWh]	$E_{el,FC}$ [kWh]	$E_{el,grid}$ [kWh]	Max $E_{el,FC}$ [kWh]	$E_{th,load}$ [kWh]	$E_{th,FC}$ [kWh]	Max $E_{residual}$ [kWh]	Max $E_{exchanged}$ [kWh]
1	6445	6295	150	8.46	21781	2623	49.69	1.85
2	5761	5686	75	8.46	16191	2370	49.83	1.85
3	6328	6295	33	8.46	10850	2623	45.59	3.53
4	6121	6092	29	8.46	2546	2539	7.52	3.53
5	6227	6295	-68	8.46	2593	2623	4.84	3.53
6	5984	6092	-108	8.46	2510	2539	4.84	3.53
7	6287	6295	-8	8.46	2593	2623	4.84	3.53
8	6168	6295	-127	8.46	2593	2623	4.84	3.53
9	5984	6092	-108	8.46	2510	2539	4.84	3.53
10	6287	6295	-8	8.46	2593	2623	4.84	3.53
11	6139	6092	47	8.46	10635	2539	39.95	3.53
12	6386	6295	92	8.46	20296	2623	49.56	1.85
Total / Max.:	**74117**	**74117**	**0**	**8.46**	**97692**	**30890**	**49.83**	**3.53**

Month	$E_{D.H.}$ [kWh]	E_{boiler} [kWh]	Max E_{boiler} [kWh]	V_{H2} [Nm^3]	c_{el} [€]	c_{th} [€]	c_{H2} [€]	c_{tot} [€]
1	5.61	19164	49.69	3625	110	2843	2281	5234
2	41.12	13863	49.83	3274	91	2051	2060	4202
3	258.31	8485	45.59	3625	94	1221	2281	3596
4	825.56	833	7.52	3508	93	1	2207	2301
5	865.66	835	4.84	3625	82	-4	2281	2358
6	837.69	808	4.84	3508	75	-4	2207	2278
7	865.48	835	4.84	3625	91	-4	2281	2367
8	865.66	835	4.84	3625	75	-4	2281	2352
9	837.87	809	4.84	3508	75	-4	2207	2278
10	865.48	835	4.84	3625	91	-4	2281	2367
11	224.85	8321	39.95	3508	93	1201	2207	3502
12	18.10	17690	49.56	3625	103	2622	2281	5006
Total / Max.:	**6511.40**	**73314**	**49.83**	**42683**	**1074**	**9913**	**26854**	**37842**

6.3.3 Scenario 3: hydrogen boiler

The scenario with the H2-ready boiler sees its generation profile perfectly matched to the load, being a device capable of delivering the required power without producing surpluses. The chosen size is sufficient to meet the consumer's load, while the electricity demand is entirely met by purchasing electricity from the grid and has the same cost as the current scenario.

The volume of hydrogen used in this scenario is much smaller than in fuel cell systems, as it only has to supply a fraction of the thermal load and none of the electrical load.

A sensitivity analysis on the percentage of hydrogen in the mixture, in this case 20%, is therefore presented in the following chapters for a more complete discussion of the subject. The annual tally results are reported in **table 6-3**.

TABLE 6-3: SCENARIO 3, ANNUAL TALLY RESULTS

Month	$E_{th,load}$ [kWh]	E_{boiler} [kWh]	Max E_{boiler} [kWh]	V_{H2} [Nm^3]	c_{el} [€]	$c_{gas/D.H.}$ [€]	c_{H2} [€]	c_{tot} [€]
1	21781	21781	53.22	542	902	3197	341	4440
2	16191	16191	53.35	403	806	2377	253	3436
3	10850	10850	49.11	270	885	1593	170	2648
4	2546	2546	11.04	63	859	374	40	1273
5	2593	2593	8.37	65	868	381	41	1290
6	2510	2510	8.37	62	837	368	39	1245
7	2593	2593	8.37	65	879	381	41	1301
8	2593	2593	8.37	65	863	381	41	1284
9	2510	2510	8.37	62	837	368	39	1245
10	2593	2593	8.37	65	879	381	41	1301
11	10635	10635	43.47	265	859	1561	166	2587
12	20296	20296	53.09	505	896	2979	318	4193
Total / Max.:	**97692**	**97692**	**53.35**	**2430**	**10371**	**14340**	**1529**	**26240**

6.4 Economic framework

This paragraph presents the economic analysis of the case study carried out as described in Chapter 4.

6.4.1 Initial costs of investment

The initial costs of investment of scenarios 1 and 2 is the sum of the purchase costs of the components (fuel cell and heat exchanger) and the supplementary expenses.

In scenario 1, the 40 kW fuel cell costs €59828, while the 36 kW exchanger costs approximately €593. The total sum of the initial costs is consequently €82172.

Compared to a traditional generator replacement, this investment has a higher cost due to the high purchase cost of the fuel cell.

In scenario 2, the 30 kW fuel cell costs €49066, while the 4 kW exchanger costs approximately €79. The total sum of the initial costs is consequently €66837.

Due to the smaller size of the plant where the fuel cell operates at constant power, it can be observed that the initial cost is much lower than in the load-following scenario.

In scenario 3, the 60 kW boiler has a market cost of €10135, which with the ancillary costs reaches a value of €13784. This scenario requires much lower initial costs than previous ones.

6.4.2 Operation cost

In scenarios 1 and 2, the operation costs are those of the cell and the exchanger, equal to 4% and 1% of its initial cost respectively.

In scenario 1, the costs are €2393 and €6 respectively, making a total of €2399.

In scenario 2, they are instead approximately €1963 and less than €1, for an annual total of approximately €1963.

In scenario 3, the boiler's operation costs are 2% of its capex, or €203.

Operation costs are higher in the first two scenarios, while they are lower in the third. This is consistent with the lower initial costs of the boiler scenario.

6.4.3 Costs of replacement

According to the assumptions made the fuel cell stack is replaced every 50000 operating hours. Since in both scenarios continuous operation is imagined (ignoring short shutdowns for maintenance or other reasons), the stack can be expected to be replaced every 6 years. The operating years 6, 12 and 18 will therefore have a negative cash flow due to this expenditure. The replacement amount is calculated on the basis of the replacement cost and its annual reduction, so the last replacements are much less expansive.

In scenario 1, the base replacement cost (27% of the initial cost increased by ancillary expenses) is €21725. The actual cost to be incurred is €11297 for the first replacement and €2520 for the others.

In scenario 2, the base replacement cost is €17817. The actual cost to be incurred is €9265 for the first replacement and €1890 for the others.

Since the boiler has no internal components to be replaced, the third scenario has no replacement costs to deal with.
The cost for replacement, although high, is not prohibitive. An investment located some years in the future would benefit from the stack cost reduction for both replacement and cell purchase cost.

6.4.4 Incentives and deductions

6.4.4.1 Deductions on initial cost of investment

Knowing the initial cost of purchasing the components, it is possible to assess for each scenario the deductions from which one can benefit. As mentioned above, the deductions cover 65% of the purchase cost of the generators, which is compensated during the first ten years of operation by constant instalments.
For scenario 1, the total amount of the deductions is €38888 and the annual rates are equals to €3889.
For scenario 2, the amount is €31893 with instalments of about €3189.
For scenario 3, the amount of deductions is €6588 repaid with instalments of about €659.
The positive cash flow due to deductions is represented as a positive contribution during the first ten years of operation.

6.4.4.2 Incentives for green energy production

Given the amount of electricity produced by the fuel cell in scenarios 1 and 2, it is possible to calculate the annual income from the incentives previously mentioned. For a conservative estimate of the amount of incentives, a value of 0.106 €/KWh per unit of electricity produced was assumed, which is the minimum amount receivable.
In scenario 1, the annual energy production is 76331 kWh, for which an incentive of €8087 is granted.
In scenario 2, energy production is equal to 74117 kWh, for which the incentive is €7853.
This revenue constitutes a positive cash flow for each operating year of scenarios 1 and 2.

6.4.4.3 Tradable securities: white certificates

The value of the white certificates obtainable from the proposed plants is always calculated on the basis of sustainably produced energy. Unlike previous incentives, the certificates can also reward the production of thermal energy, which is then counted as electricity. The price of a blank certificate is assumed to be €250 [28].
The energy produced in one year in scenario 1 is 121208 kWh, or 22.67 toe. The relative value of certificates is therefore €5666.
In scenario 2 the overall energy is 105007 kWh, equivalent to 19.64 toe. The value of the certificates in this case is €4909.
In scenario 3, the total thermal energy produced is 97692 kWh. Of this, the energy produced from hydrogen is only 6854 kWh, while the remaining is produced from natural

gas and therefore not incentivized. The value of interest for the incentive is therefore equivalent to 1.28 toe, for which €320 in certificates can be released.
Because of these certificates constitute an incentive that cannot be combined with other forms of incentives on the sale of energy, white certificates compete with the incentives of the Decree draft previously described.
Since the latter's are higher, they will be adopted in scenarios 1 and 2, and . In scenario 3 there is no production of electricity and white certificates can be adopted. However, the value of the incentives in this case is so low that it is not considered worthwhile to carry out the relevant paperwork and is therefore neglected.

Table 6-4 summarizes the metrics discussed for the calculation of incentives.

TABLE 6-4: SPECIFICATIONS OF INCENTIVES

White certificates			
White certificate value:		250	€
Energy requirements (equivalent savings):		1	toe
Conversion factor of kWh to toe:		0.000187	toe/kWh
Energy produced with green hydrogen:	*Scenario 1*	121208	kWh
	Scenario 2	105007	kWh
	Scenario 3	6854	kWh
Equivalent toe produced with green hydrogen:	*Scenario 1*	22.67	toe
	Scenario 2	19.64	toe
	Scenario 3	1.28	toe
Potential annual revenue:	*Scenario 1*	5666	€
	Scenario 2	4909	€
	Scenario 3	320	€
Ministerial Decree Draft			
Potential annual revenue:	*Scenario 1*	8087	€
	Scenario 2	7853	€

6.4.5 Scenario 1: load-following fuel cell

The overall economic analysis of the first scenario shows that the proposed intervention is characterised by a high initial cost and a negative end-of-life net present value. Under current conditions, the application of this scenario does not lead to an economic benefit. The costs for the installation are largely located in the purchase cost of the components, although these enjoy incentives for 65% of their value. The operating costs during the life of the installation, although high, take the form of annual instalments of less than the amount compensated by the deductions. Replacement costs are high for the first replacement, and much lower for the following ones.
Table 6-5 shows all the economic parameters discussed above for the first scenario.

TABLE 6-5: SCENARIO 1, ECONOMIC FRAMEWORK

	Capex:		Opex:		Replacement:	
Fuel cell:	59828	€	2393	€	15974	€
Heat exchanger:	593	€	6	€		
Total of components:	60421	€	2399	€	60421	€
Estimated ancillary costs:	21751	€			5751	€
Total:	82172	€	2399	€	21725	€

Incentives:			Deductions:				
Incentives:	0.106	€/kWh		**Overall value:**		**Annual payment:**	
	8087	€	**Fuel cell:**	38888	€	3889	€

Figure 6-5 shows the development of the first scenario's net present value over the years of the plant's life.
During the first three years of operation, a worsening trend is observed due to the high cost of hydrogen. The non-linear shape of the graph is due to the price of hydrogen decreasing linearly until the limit value of €2/kg is reached. In the sixth year, a steep decrease is observed due to the first more expensive replacement of the fuel cell stack. From year six until year 20, cash flows are positive. From this it can be deduced that, having reached a competitive price, hydrogen can be used in this way to lower the cost of electricity and heat utilities. The twelfth and eighteenth years show a slight decrease

due to stack replacement costs. Unlike the first substitution, the others have a much lower cost and the overall balance of the respective year remains positive.

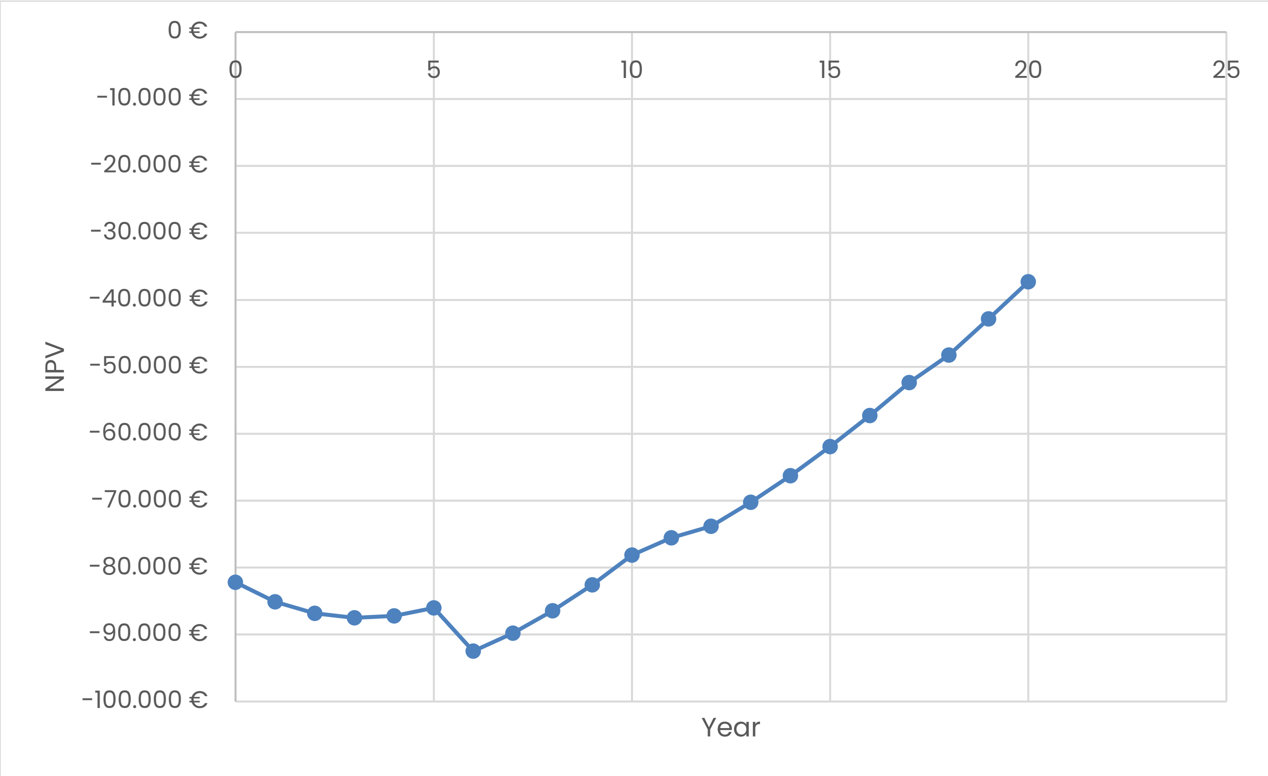


FIGURE 6-5: SCENARIO 1, NET PRESENT VALUE

Table 6-6 details the first scenario's cash flows for each year.

The annual value of electricity in this scenario is positive and constitutes a small economic income. This is motivated by the fact that the cell cannot produce less than the cut-off power and can therefore produce more electricity than is actually consumed. The excess energy is sold into the grid and is therefore remunerated.

TABLE 6-6: SCENARIO 1, CASH FLOWS

Year	Capex	Opex	Replacement	Deductions and incentives	Electricity cost	Thermal energy cost	Hydrogen cost	Savings compared to the current state	Annual cash flow	Discounted annuity year 0	NPV
0	-82.172 €	0 €	0 €	0 €	0 €	0 €	0 €	0 €	-82.172 €	-82.172 €	-82.172 €
1		-2.399 €	0 €	11.976 €	226 €	-7.872 €	-30.783 €	25.793 €	-3.059 €	-2.913 €	-85.085 €
2		-2.399 €	0 €	11.976 €	226 €	-7.872 €	-29.643 €	25.793 €	-1.919 €	-1.740 €	-86.826 €
3		-2.399 €	0 €	11.976 €	226 €	-7.872 €	-28.503 €	25.793 €	-778 €	-672 €	-87.498 €
4		-2.399 €	0 €	11.976 €	226 €	-7.872 €	-27.362 €	25.793 €	362 €	298 €	-87.201 €
5		-2.399 €	0 €	11.976 €	226 €	-7.872 €	-26.222 €	25.793 €	1.502 €	1.177 €	-86.024 €
6		-2.399 €	-11.297 €	11.976 €	226 €	-7.872 €	-25.082 €	25.793 €	-8.655 €	-6.459 €	-92.482 €
7		-2.399 €	0 €	11.976 €	226 €	-7.872 €	-23.942 €	25.793 €	3.782 €	2.688 €	-89.795 €
8		-2.399 €	0 €	11.976 €	226 €	-7.872 €	-22.802 €	25.793 €	4.922 €	3.331 €	-86.463 €
9		-2.399 €	0 €	11.976 €	226 €	-7.872 €	-21.662 €	25.793 €	6.062 €	3.908 €	-82.556 €
10		-2.399 €	0 €	11.976 €	226 €	-7.872 €	-20.522 €	25.793 €	7.202 €	4.422 €	-78.134 €
11		-2.399 €	0 €	8.087 €	226 €	-7.872 €	-19.382 €	25.793 €	4.454 €	2.604 €	-75.530 €
12		-2.399 €	-2.520 €	8.087 €	226 €	-7.872 €	-18.242 €	25.793 €	3.074 €	1.712 €	-73.819 €
13		-2.399 €	0 €	8.087 €	226 €	-7.872 €	-17.102 €	25.793 €	6.734 €	3.571 €	-70.248 €
14		-2.399 €	0 €	8.087 €	226 €	-7.872 €	-15.961 €	25.793 €	7.874 €	3.977 €	-66.271 €
15		-2.399 €	0 €	8.087 €	226 €	-7.872 €	-14.821 €	25.793 €	9.014 €	4.336 €	-61.935 €
16		-2.399 €	0 €	8.087 €	226 €	-7.872 €	-13.681 €	25.793 €	10.154 €	4.652 €	-57.283 €
17		-2.399 €	0 €	8.087 €	226 €	-7.872 €	-12.541 €	25.793 €	11.294 €	4.928 €	-52.356 €
18		-2.399 €	-2.520 €	8.087 €	226 €	-7.872 €	-11.401 €	25.793 €	9.914 €	4.120 €	-48.236 €
19		-2.399 €	0 €	8.087 €	226 €	-7.872 €	-10.261 €	25.793 €	13.574 €	5.372 €	-42.864 €
20		-2.399 €	0 €	8.087 €	226 €	-7.872 €	-9.121 €	25.793 €	14.714 €	5.546 €	-37.319 €

6.4.6 Scenario 2: constant-power fuel cell

The overall economic analysis of the second scenario shows that also the costant-power regime is is penalised by from a high initial cost and a negative end-of-life net present value. Under current conditions, the application of this scenario leads to a loss-making investment.

The costs for the installation are largely located in the purchase cost of the components, despite incentives. The operating costs during the life of the installation, although high, take the form of annual instalments of less than the amount compensated by the deductions. Replacement costs are high for the first replacement, and much lower for the following ones.

The following table shows all the economic parameters discussed above for the second scenario.

Compared to the first scenario, the lower initial costs and higher efficiency lead to a higher net present value in the 20th year, albeit a negative one.

Table 6-2 summarises the economic metrics of the second scenario.

TABLE 6-2: SCENARIO 2, ECONOMIC FRAMEWORK

	Capex:		Opex:		Replacement:		
Fuel cell:	49066	€	1963	€	13101		€
Heat exchanger:	79	€	1	€			
Total of components:	49145	€	1963	€	13101		€
Estimated ancillary costs:	17692	€			4716		€
Total:	66837	€	1963	€	17817		€
Incentives:			**Deductions:**				
Incentives:	0.106	€/kWh		**Overall value:**		**Annual payment:**	
	7853	€	**Fuel cell:**	31893	€	3189	€

Figure 6-6 shows the development of the second scenario's net present value over the years of the plant's life.

The development of the present value of the investment follows almost entirely that of the previous scenario. From this can be concluded the importance of reducing the cost of hydrogen for this type of technology.

A sensitivity analysis on the cost of hydrogen is presented in a later chapter.

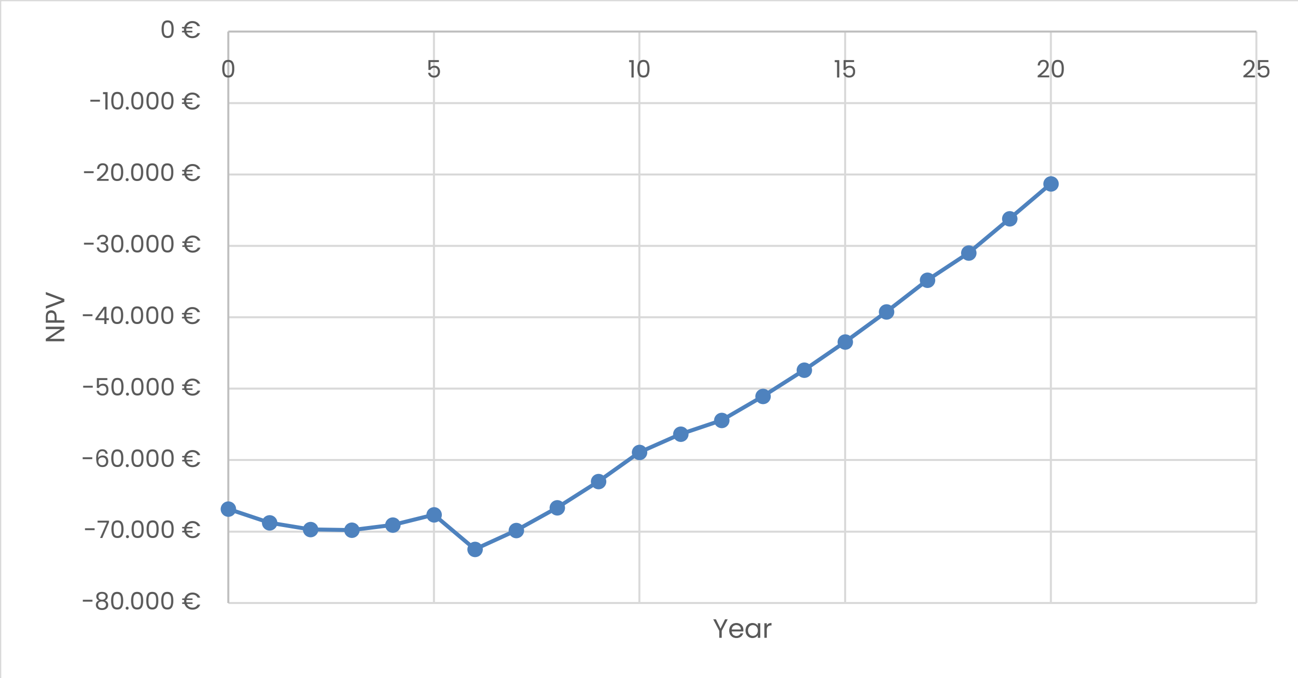


FIGURE 6-6: SCENARIO 2, NET PRESENT VALUE

Table 6-7 details the second scenario's cash flows for each year.
The annual value of electricity in this scenario is negative, in contrast to the previous scenario. This is motivated by the fact that part of the energy actually consumed is purchased from the grid at a slightly lower price than when the same energy is later fed in and sold.

TABLE 6-7: SCENARIO 2, CASH FLOWS

Year	Capex	Opex	Replacement	Deductions and incentives	Electricity cost	Thermal energy cost	Hydrogen cost	Savings compared to the current state	Annual cash flow	Discounted annuity year 0	NPV
0	-66.837 €	0 €	0 €	0 €	0 €	0 €	0 €	0 €	-66.837 €	-66.837 €	-66.837 €
1		-1.963 €	0 €	11.042 €	-1.074 €	-9.913 €	-25.895 €	25.793 €	-2.011 €	-1.915 €	-68.752 €
2		-1.963 €	0 €	11.042 €	-1.074 €	-9.913 €	-24.936 €	25.793 €	-1.052 €	-954 €	-69.706 €
3		-1.963 €	0 €	11.042 €	-1.074 €	-9.913 €	-23.977 €	25.793 €	-92 €	-80 €	-69.786 €
4		-1.963 €	0 €	11.042 €	-1.074 €	-9.913 €	-23.018 €	25.793 €	867 €	713 €	-69.073 €
5		-1.963 €	0 €	11.042 €	-1.074 €	-9.913 €	-22.059 €	25.793 €	1.826 €	1.430 €	-67.642 €
6		-1.963 €	-9.265 €	11.042 €	-1.074 €	-9.913 €	-21.100 €	25.793 €	-6.480 €	-4.835 €	-72.478 €
7		-1.963 €	0 €	11.042 €	-1.074 €	-9.913 €	-20.141 €	25.793 €	3.744 €	2.661 €	-69.817 €
8		-1.963 €	0 €	11.042 €	-1.074 €	-9.913 €	-19.182 €	25.793 €	4.703 €	3.183 €	-66.634 €
9		-1.963 €	0 €	11.042 €	-1.074 €	-9.913 €	-18.223 €	25.793 €	5.662 €	3.650 €	-62.984 €
10		-1.963 €	0 €	11.042 €	-1.074 €	-9.913 €	-17.263 €	25.793 €	6.621 €	4.065 €	-58.920 €
11		-1.963 €	0 €	7.853 €	-1.074 €	-9.913 €	-16.304 €	25.793 €	4.391 €	2.567 €	-56.352 €
12		-1.963 €	-1.890 €	7.853 €	-1.074 €	-9.913 €	-15.345 €	25.793 €	3.460 €	1.927 €	-54.426 €
13		-1.963 €	0 €	7.853 €	-1.074 €	-9.913 €	-14.386 €	25.793 €	6.309 €	3.346 €	-51.080 €
14		-1.963 €	0 €	7.853 €	-1.074 €	-9.913 €	-13.427 €	25.793 €	7.268 €	3.671 €	-47.409 €
15		-1.963 €	0 €	7.853 €	-1.074 €	-9.913 €	-12.468 €	25.793 €	8.227 €	3.957 €	-43.452 €
16		-1.963 €	0 €	7.853 €	-1.074 €	-9.913 €	-11.509 €	25.793 €	9.186 €	4.208 €	-39.243 €
17		-1.963 €	0 €	7.853 €	-1.074 €	-9.913 €	-10.550 €	25.793 €	10.145 €	4.426 €	-34.817 €
18		-1.963 €	-1.890 €	7.853 €	-1.074 €	-9.913 €	-9.591 €	25.793 €	9.214 €	3.829 €	-30.988 €
19		-1.963 €	0 €	7.853 €	-1.074 €	-9.913 €	-8.632 €	25.793 €	12.064 €	4.774 €	-26.214 €
20		-1.963 €	0 €	7.853 €	-1.074 €	-9.913 €	-7.673 €	25.793 €	13.023 €	4.908 €	-21.306 €

6.4.7 Scenario 3: hydrogen boiler

The overall economic analysis of the third scenario shows that the proposed intervention has a minor initial cost and, also in this case, a negative end-of-life net present value. Replacing a conventional thermal generator with an H2-ready variant is not a positive economic investment for the conditions assumed in this research.
The initial costs are exclusively in the purchase cost of the generator. The operating costs are lower compared to those of previous systems. Replacement costs are absent.
Table 6-8 shows all the economic parameters discussed above for the third scenario.

TABLE 6-8: SCENARIO 3, ECONOMIC FRAMEWORK

	Capex:		Opex:	
Boiler:	10135	€	203	€
Estimated ancillary costs:	3649	€		
Total:	13784	€	203	€
Deductions:				
	Overall value:		**Annual payment:**	
Boiler:	6588	€	659	€

Figure 6-7 the development of the third scenario's net present value over the years of the plant's life.
Although the cost of hydrogen energy is higher than that of energy from conventional grids, annual cash flows are positive in the early years. This is motivated by the fact that annual deductions compensate for the limited increase in energy costs, which are only minimally dependent on hydrogen. The eleventh year, which is the first after the end of the deduction refund, has a negative cash flow of a few tens of euros. The following years are positive again, as hydrogen has reached such a low price that it is worthwhile compared to buying gas.
Compared to the NPV trends of the previous scenarios, a greater linearity in costs can be seen, due to the lower incidence of hydrogen in the cost mix. Conversely, for the same reason a lower growth of cash flows is also observed as the years go by.

For more detail on the impact of the percentage of hydrogen in the mixture on the intervention, a sensitivity analysis on this parameter is presented in a later chapter.

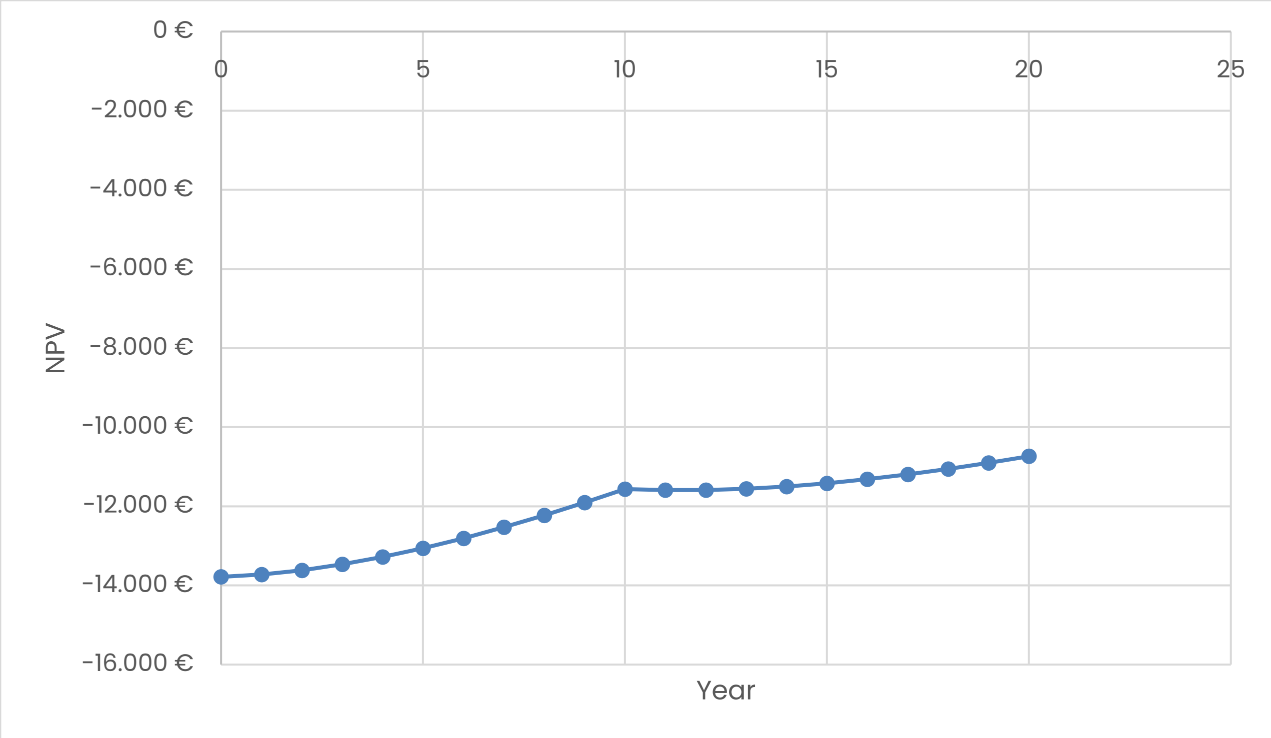


FIGURE 6-7: SCENARIO 3, NET PRESENT VALUE

Table 6-9 details the third scenario's cash flows for each year.
The annual value of electricity in this scenario is the same as the state of affairs, since no changes were made to electricity production. In order to lower this significant cost, parallel interventions can be made on the conversion of the electricity supply, such as the installation of photovoltaic panels. The same use of H2-ready boilers is not precluded when fuel cell systems such as those studied in scenarios 1 and 2 are adopted.

TABLE 6-9: SCENARIO 3, CASH FLOWS

Year	Capex	Opex	Replacement	Deductions and incentives	Electricity cost	Thermal energy cost	Hydrogen cost	Savings compared to the current state	Annual cash flow	Discounted annuity year 0	NPV
0	-13.784 €	0 €	0 €	0 €	0 €	0 €	0 €	0 €	-13.784 €	-13.784 €	-13.784 €
1		-203 €	0 €	659 €	-10.371 €	-14.340 €	-1.475 €	25.793 €	64 €	60 €	-13.723 €
2		-203 €	0 €	659 €	-10.371 €	-14.340 €	-1.420 €	25.793 €	118 €	107 €	-13.616 €
3		-203 €	0 €	659 €	-10.371 €	-14.340 €	-1.365 €	25.793 €	173 €	149 €	-13.467 €
4		-203 €	0 €	659 €	-10.371 €	-14.340 €	-1.311 €	25.793 €	227 €	187 €	-13.280 €
5		-203 €	0 €	659 €	-10.371 €	-14.340 €	-1.256 €	25.793 €	282 €	221 €	-13.059 €
6		-203 €	0 €	659 €	-10.371 €	-14.340 €	-1.201 €	25.793 €	337 €	251 €	-12.808 €
7		-203 €	0 €	659 €	-10.371 €	-14.340 €	-1.147 €	25.793 €	391 €	278 €	-12.530 €
8		-203 €	0 €	659 €	-10.371 €	-14.340 €	-1.092 €	25.793 €	446 €	302 €	-12.228 €
9		-203 €	0 €	659 €	-10.371 €	-14.340 €	-1.038 €	25.793 €	500 €	323 €	-11.905 €
10		-203 €	0 €	659 €	-10.371 €	-14.340 €	-983 €	25.793 €	555 €	341 €	-11.565 €
11		-203 €	0 €	0 €	-10.371 €	-14.340 €	-928 €	25.793 €	-49 €	-29 €	-11.593 €
12		-203 €	0 €	0 €	-10.371 €	-14.340 €	-874 €	25.793 €	5 €	3 €	-11.590 €
13		-203 €	0 €	0 €	-10.371 €	-14.340 €	-819 €	25.793 €	60 €	32 €	-11.558 €
14		-203 €	0 €	0 €	-10.371 €	-14.340 €	-765 €	25.793 €	115 €	58 €	-11.500 €
15		-203 €	0 €	0 €	-10.371 €	-14.340 €	-710 €	25.793 €	169 €	81 €	-11.419 €
16		-203 €	0 €	0 €	-10.371 €	-14.340 €	-655 €	25.793 €	224 €	103 €	-11.316 €
17		-203 €	0 €	0 €	-10.371 €	-14.340 €	-601 €	25.793 €	279 €	122 €	-11.195 €
18		-203 €	0 €	0 €	-10.371 €	-14.340 €	-546 €	25.793 €	333 €	138 €	-11.056 €
19		-203 €	0 €	0 €	-10.371 €	-14.340 €	-492 €	25.793 €	388 €	153 €	-10.903 €
20		-203 €	0 €	0 €	-10.371 €	-14.340 €	-437 €	25.793 €	442 €	167 €	-10.736 €

6.5 Sensitivity analyses

Perché si è scelto di fare un'analisi di sensitività? Quali parametri si è scelto di far variare e perché?

In order to deepen the research and feasibility of the investigated systems, some sensitivity analyses on the most impactful parameters are presented in this section.

From the economic analysis conducted on the different scenarios, it was determined that the main parameter to be analysed is the cost of hydrogen, which is currently higher than the cost of energy from traditional sources. An initial sensitivity analysis is therefore conducted and presented below on the change in the purchase price of the hydrogen resource.

A second aspect investigated is the contribution of thermal storage. This component was not included in the installations of the case study as it was assumed that a connection to the district heating network would be available. Therefore, a sensitivity analysis on the size of a thermal storage was carried out to investigate the feasibility of these interventions when district heating was not available.

Lastly, a sensitivity analysis is conducted on the variation of the percentage of hydrogen in the mixture burnt by the H2-ready boiler, of which two observations about the 100% and 0% values are anticipated. A fraction of 100% of hydrogen burned in a boiler constitutes a conceptually different use than in fuel cells, where it is electrochemically broken down. A 0% fraction, on the other hand, allows a comparison to be made between a hydrogen boiler and a conventional one fueled solely by gas.

6.5.1 Hydrogen price

We proceed with the description of the impact of a change in the initial purchase price of the hydrogen resource.

A sensitivity analysis is presented below on the net present value of each of the three scenarios as the initial hydrogen price changes at year zero. It is assumed that this cost decreases linearly each year until it reaches the minimum value of 2 €/kg in the twentieth year of the investment.

6.5.1.1 Scenario 1

From the first scenario, can be immediately noticed that the driving force for economic feasibility is the price of green hydrogen, which is currently too high. With the price assumed for the case study of 7 €/kg, the investment would have a negative net present value at the end of its life, while with an initial price of 5.5 €/kg, the investment has a payback time of between 18 and 19 years and a net present value at year 20 of € 9982. at a IRR equal to 1.044%.

With an hydrogen price higher than 7 €/kg, it can be observed how the investment can be strongly negative from an economic point of view.

Figure 6-8 shows the NPV of the first scenario as the initial hydrogen cost changes.

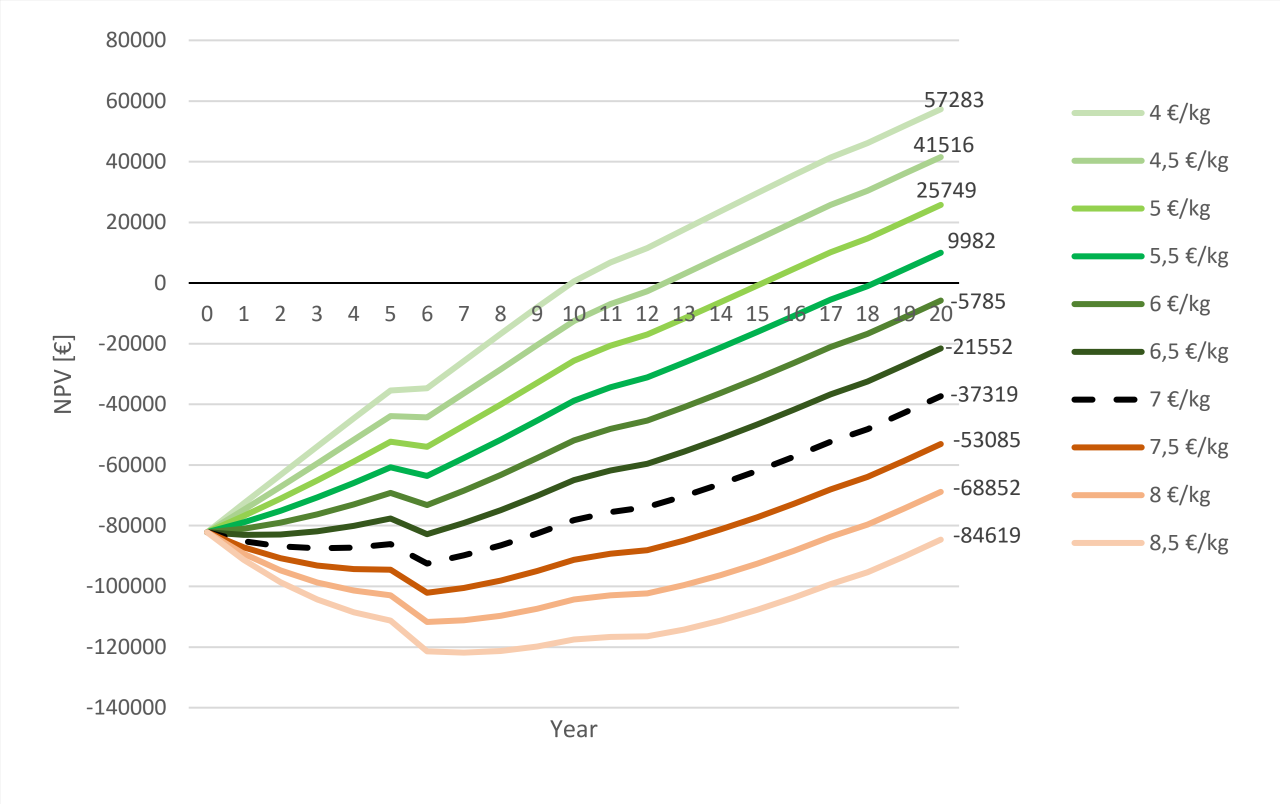


FIGURE 6-8: SENSITIVITY ANALYSIS ABOUT HYDROGEN INITIAL PURCHASE PRICE – SCENARIO 1

The graph presented confirms the conclusions drawn in the economic analysis of this scenario. A greater variation in the cost of hydrogen has a significant effect on the economics of the investment. The purchase price of hydrogen affects the slope of the NPV trend, which takes non-linear forms the higher the cost is.

Table 6-3 summarises the economic indicators of payback time, IRR and NPV of the higher initial hydrogen value to make the investment positive.

TABLE 6-3: ECONOMIC INDICATORS OF THE HIGHER H_2 COST WITH POSITIVE NPV, SCENARIO 1

Initial hydrogen cost:	5.5	€/kg
Payback time	18-19	years
Internal rate of return:	1.044	%
NPV (end life):	9982	€

For sufficiently low values of the cost of hydrogen, even with high initial costs, the investment would offer a reasonable return.

6.5.1.2 Scenario 2

In the second scenario, a less pronounced dependence on the change in the price of hydrogen is observed. This is motivated by a lower consumption of the resource than in the previous scenario, since the potential gain (or loss) from a change in the price of the raw material increases as the quantity of the resource used increases.

The minimum initial cost that hydrogen must reach to achieve a positive NPV is €6/kg in this scenario, which implies a payback time of between 18 and 19 years and an NPV at the end of plant life of €5221. The IRR of this initial price is 0.637%. **Figure 6-9** shows the NPV of the second scenario as the initial hydrogen cost changes.

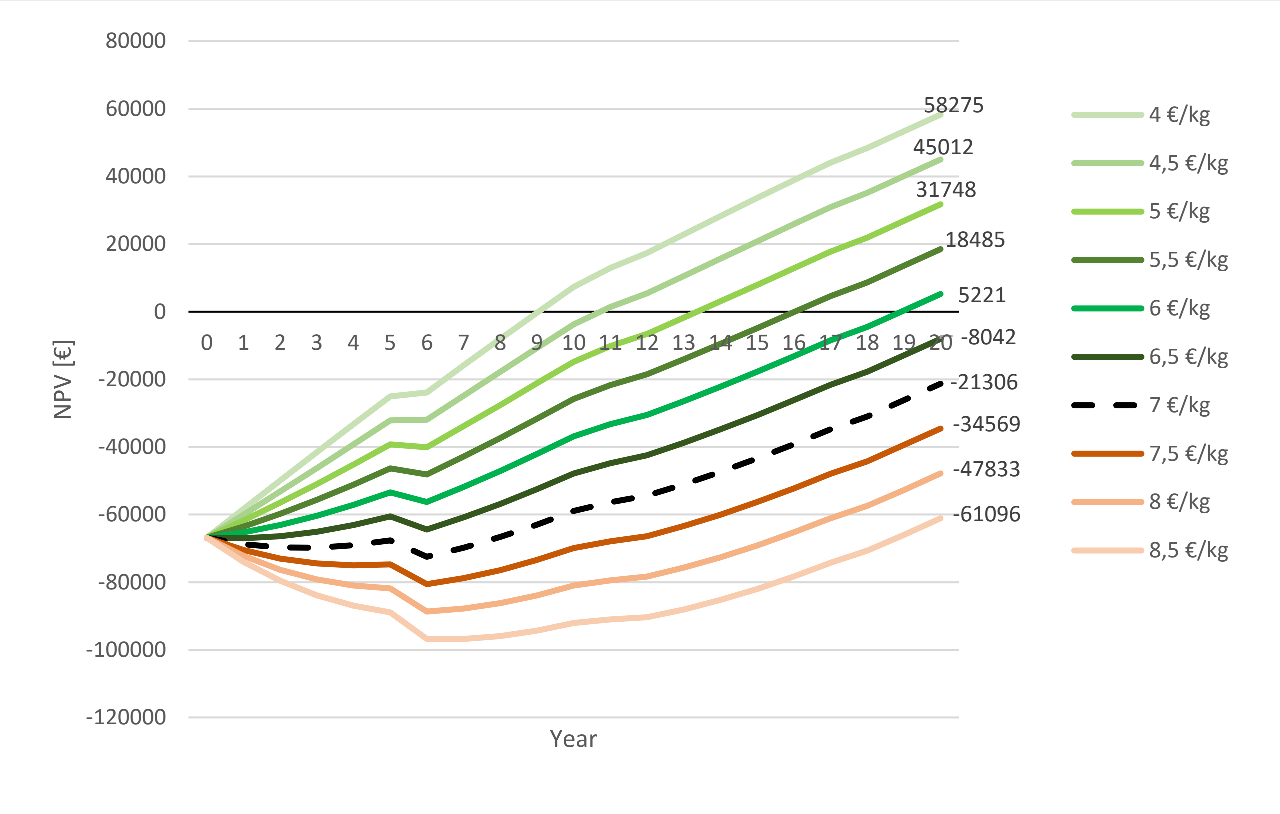


FIGURE 6-9: SENSITIVITY ANALYSIS ABOUT HYDROGEN INITIAL PURCHASE PRICE – SCENARIO 2

Compared to the first scenario, the sensitivity analysis shows that the second scenario is not only more profitable but is also less exposed to possible increases in the cost of hydrogen, constituting a less risky investment. This is consistent with being less dependent on the hydrogen resource, differentiating its energy mix with a higher fraction of energy from traditional sources. Conversely, any increases in electricity from the grid or gas may affect this operating regime more than load-following.

Table 6-4 shows the values of the first positive NPV previously described.

TABLE 6-4: ECONOMIC INDICATORS OF THE HIGHER H_2 COST WITH POSITIVE NPV, SCENARIO 2

Initial hydrogen cost:	6	€/kg
Payback time	18-19	years
Internal rate of return:	0.637	%
NPV (end life):	5221	€

6.5.1.3 Scenario 3

As can be seen in the figure above, each scenario does not achieve a positive net present value even with a large hydrogen cost discount. The reasons for this are to be found in the low percentage of hydrogen that is assumed to be burned in the boiler (only 20%). The convenience of upgrading a utility's conventional boiler with a hydrogen boiler thus

lies largely in the volumetric flow rate of hydrogen it can handle, rather than in the cost of the hydrogen resource alone.
A sensitivity analysis on the percentage of hydrogen in the mixture is conducted and described in a following paragraph.
Figure 6-10 shows the NPV of the third scenario as the initial hydrogen cost changes.

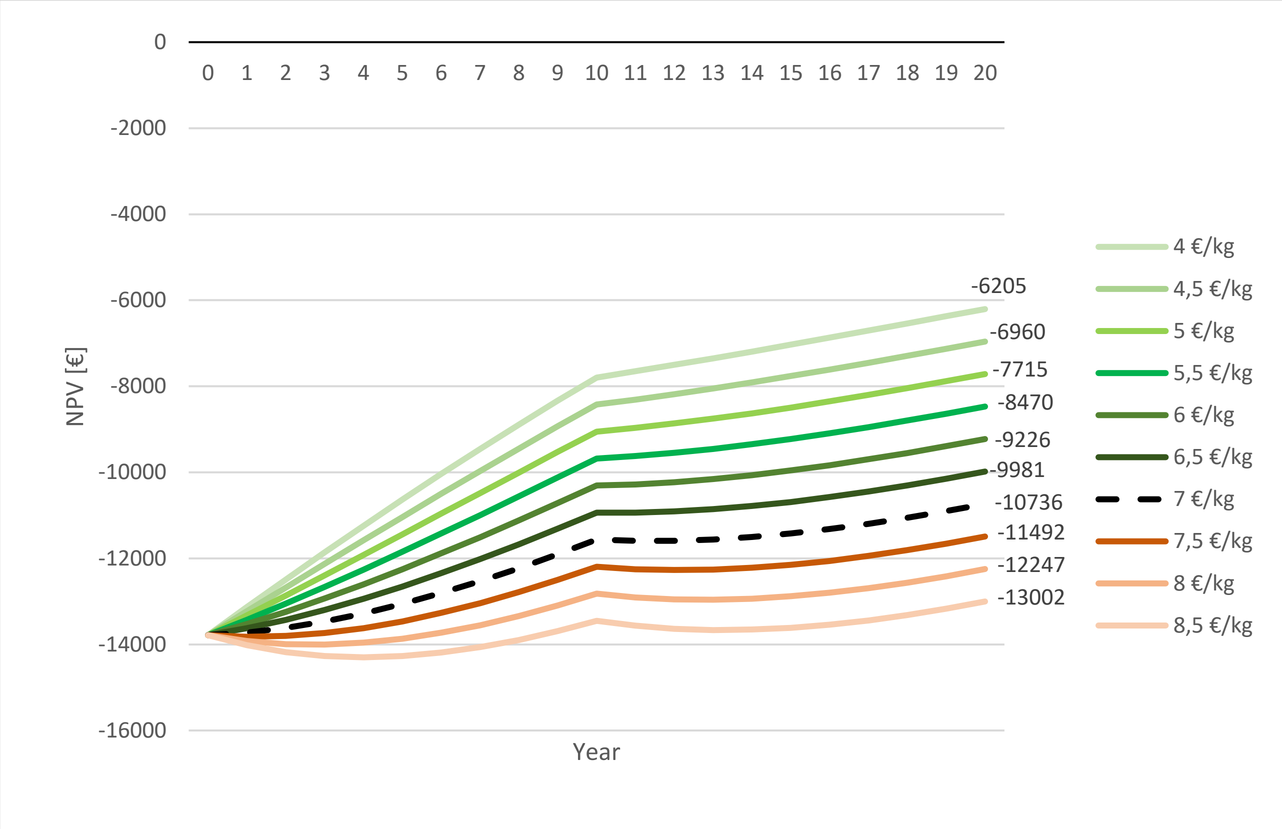


FIGURE 6-10: SENSITIVITY ANALYSIS ABOUT HYDROGEN INITIAL PURCHASE PRICE – SCENARIO 3

From this analysis, it can be observed that a change in the price of hydrogen has a less pronounced effect on annual cash flows than in previous scenarios. This is motivated by the lower consumption of the resource compared to plants where it is also used to generate electricity. Compared to the fuel cell scenarios, the adoption of an H2-ready boiler is an intervention with a much less innovative connotation and more aligned to the merits and shortcomings of the traditional generation paradigm.

6.5.2 Thermal storage size

As described above, for the case study it was decided to distribute the excess heat produced by the fuel cell to a district heating network instead of storing it into a local thermal storage.
For the sake of completeness, it is set out what the performance would be in the case (not discussed in its entirety) where a storage system is installed. To this end, a sensitivity analysis was conducted on the size of the storage facility, in order to verify whether and

which size of the tank constitutes a positive economic contribution to the system if the district heating network was not available.
The calculation of the storage performance was conducted by performing the annual energy simulation on both scenarios for each of the 20 sizes available in the simulator's archive, from 200 L up to 20000 L. In each simulation, the withdrawals made from the storage, namely the amount of energy actually saved by the storage, were calculated, and the economic value of this energy was calculated accordingly. Through a comparison between the cost of storage and the value of the energy it conserves, the economic effect, whether better or worse, that its presence can bring is calculated.
The technical specifications of the accumulation are as discussed above, and its price is assumed incentivized for the 65% of the purchase cost. The storage cost for each volume is obtained from market research, mainly from [19].
The results are reported in **table 6-5**.

TABLE 6-5: SENSITIVITY ANALYSIS ABOUT STORAGE SIZE

			Scenario 1:			***Scenario 2:***		
Volume [L]:	**Storage market price [€]:**	**Storage incentivized price [€]:**	**Energy savings [kWh]:**	**Value of energy savings [€]:**	**Economic contribution [€]:**	**Energy savings [kWh]:**	**Value of energy savings [€]:**	**Economic contribution [€]:**
0	0	0	0	0	0	0	0	0
200	675	236	4168	618	382	4448	660	424
300	838	293	5486	814	521	5621	834	541
500	1109	388	7522	1116	728	6325	939	550
600	1217	426	8244	1223	797	6333	940	514
750	1498	524	8559	1270	746	6343	941	417
800	1605	562	8651	1284	722	6346	942	380
1000	1763	617	8900	1321	704	6357	943	326
1250	2554	894	9070	1346	452	6371	945	51
1500	2643	925	9119	1353	428	6384	947	22
2000	3444	1205	9177	1362	156	6402	950	-255
2500	3674	1286	9211	1367	81	6414	952	-334
3000	5380	1883	9238	1371	-512	6425	953	-930
4000	6190	2167	9291	1379	-788	6443	956	-1210
4500	8313	2910	9317	1382	-1527	6451	957	-1952
5000	8850	3098	9342	1386	-1711	6459	958	-2139
6000	9952	3483	9393	1394	-2089	6474	961	-2523
8000	10493	3673	9494	1409	-2264	6500	965	-2708
10000	17688	6191	9593	1424	-4767	6524	968	-5223
12000	18793	6578	9692	1438	-5139	6546	971	-5606
20000	27386	9585	10081	1496	-8089	6620	982	-8603

The sensitivity analysis shows that the cost of an over-capacity storage tank may exceed the savings effect of not installing it. The same economic optimum is not necessarily at a high capacity, and can be found for 600 L for scenario 1 and 500 L for scenario 2.

Values in excess of 2500 L for the first scenario and 1500 for the second entail only a cost and not a gain, although the savings in environmental terms grow continuously as the capacity increases.
These results are motivated due to the not very high operating temperature of the fuel cell. Different types of cells can make the most of the value of on-site storage.
Figure 6-11 and **6-12** show, for each scenario, the capacity values of greatest interest, where the storage is convenient.

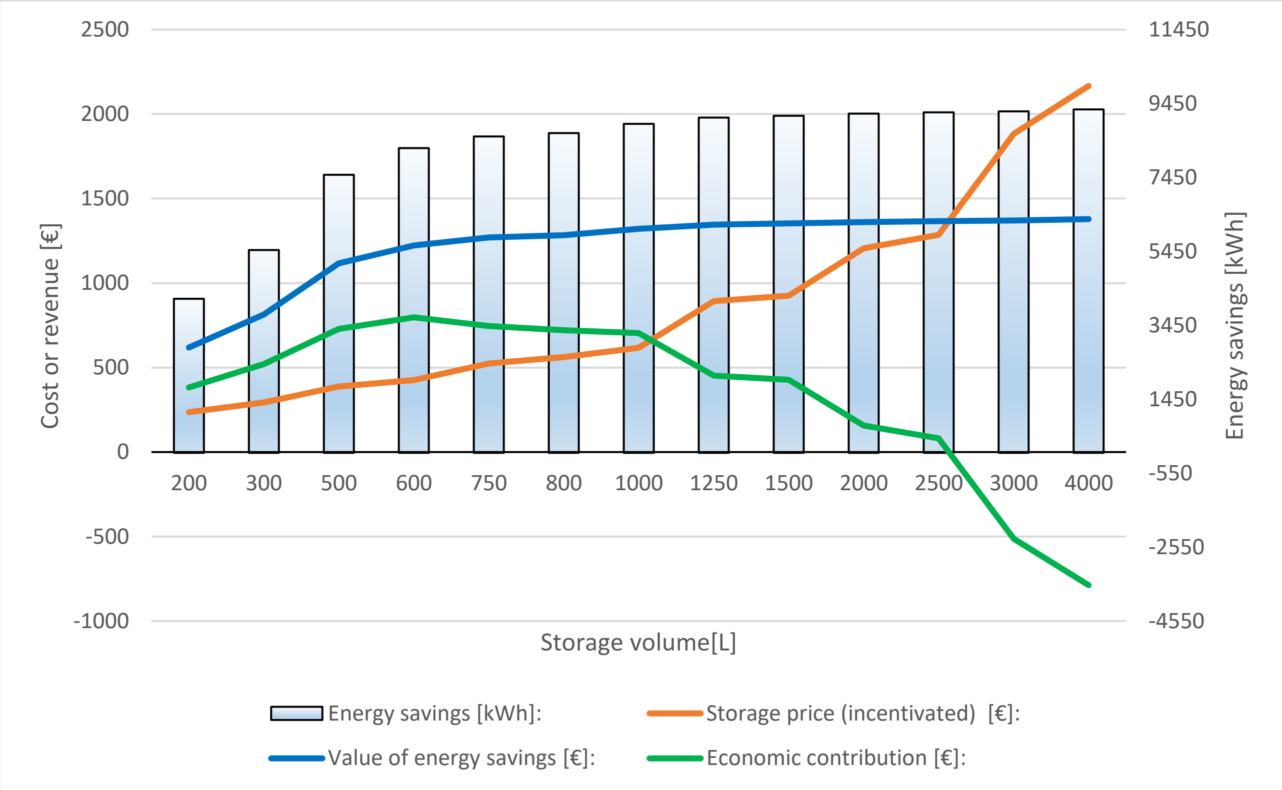


FIGURE 6-11: SENSITIVITY ANALYSIS ABOUT THERMAL STORAGE SIZE – SCENARIO 1

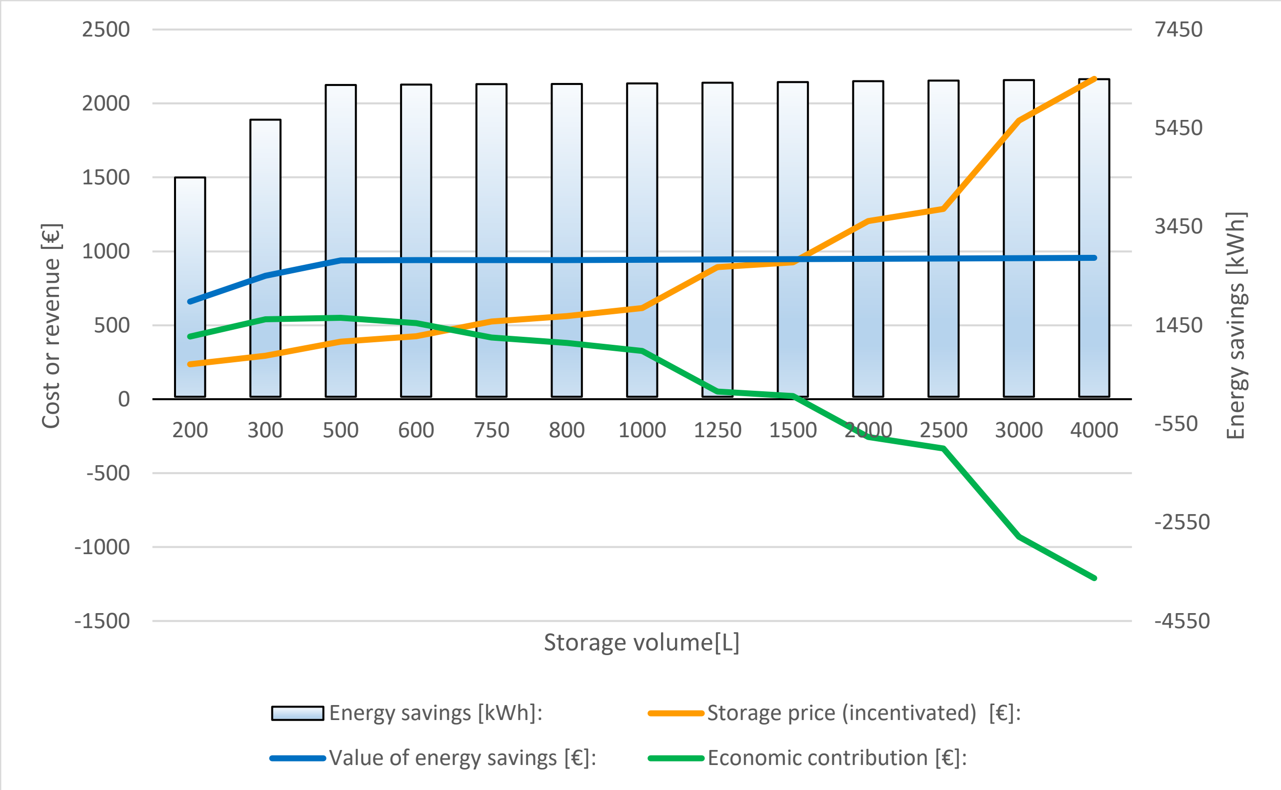


FIGURE 6-12: SENSITIVITY ANALYSIS ABOUT THERMAL STORAGE SIZE – SCENARIO 2

6.5.3 Percentage of hydrogen in mixture

The sensitivity analysis inherent to the percentage of hydrogen in the gas mixture fed into the H2-ready boiler is presented below. It should be noted that the models currently on the market, such as the one in the case study, can currently receive a hydrogen percentage of 20%.
The following graph shows the net present value of the investment for different percentages of hydrogen burned in the boiler.

The value of 0% of hydrogen represents the performance of a conventional boiler using only gas. The cost of such a device can be compared to an H2-ready model of the same rated power. A comparison between the traditional and H2-ready versions can be formulated on the basis of the NPV of the two scenarios, assuming the same sizing and incentive assumptions.

From the data represented in **figure 6-13** it can be seen that each boiler replacement scenario represents a negative investment and never an economic gain.
There is an initial phase where costs are higher the greater the percentage of hydrogen used. This is motivated by the fact that the initial cost of hydrogen is higher than that of gas energy. Over time, applying the reduction in the cost of hydrogen discussed above, it reaches a lower value than methane and the scenarios tend to become cost-effective.

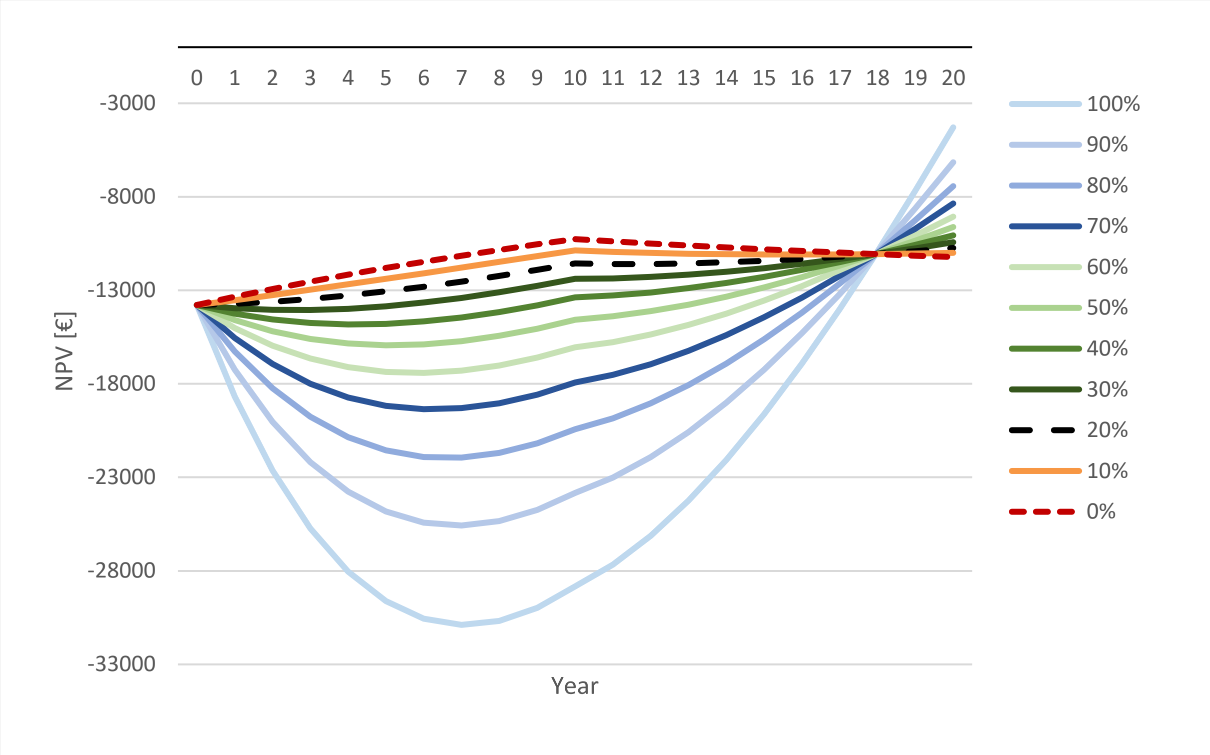


FIGURE 6-13: SENSITIVITY ANALYSIS ABOUT THE PERCENTAGE OF HYDROGEN IN THE MIXTURE – SCENARIO 3

Table 6-6 shows the net present values at year 20 for each percentage of hydrogen in mixture.

TABLE 6-6: NPV (20TH YEAR) OF SCENARIO 3 FOR DIFFERENT PERCENTAGE OF HYDROGEN IN MIXTURE

Percentage of hydrogen in mixture	NPV (at 20th year) [€]
0% (traditional boiler)	-11223
10%	-10998
20% (case study boiler)	-10736
30%	-10429
40%	-10061
50%	-9615
60%	-9062
70%	-8357
80%	-7430
90%	-6154
100% (full hydrogen boiler)	-4288

A convergence point of the scenarios can be observed around the eighteenth year of investment, beyond which the hydrogen use rate is rewarded by a cost reduction.
A comparison of the case study scenario (20% hydrogen, €7/kg initial cost) with the scenario of a conventional boiler (0% hydrogen) leads to the conclusion that the purchase of an H2-ready boiler is, albeit slightly, cost-effective in the long run, although it entails an initial period of higher energy expenditure.

From the strong dependence of NPV on hydrogen percentage, it is concluded that, for lower hydrogen prices than today, the replacement of a conventional boiler with a later generation variant can easily constitute a decarbonisation intervention that pays for itself over time.

7 Conclusions

Hydrogen represents a practical and marketable way to decarbonise the energy sector. Among its strengths are its ability to replace other polluting fuels and the fact that it can be produced renewably, helping to mitigate the problem of intermittent renewable energy sources. The use of non-green hydrogen as opposed to fossil fuels, although currently considerably cheaper than its sustainably produced variant, can help reduce pollutant emissions at the site of consumption, but without improving the overall situation due to the emissions its production requires.

The widespread diffusion of hydrogen requires infrastructure and production investments currently already planned in most industrialised countries, including the European Union, which will lead in the near future to greater availability in quantity and more efficient and cheaper production of the resource.

Similar to the production aspect of hydrogen, technologies using hydrogen will also benefit from a learning-factor due to increased market demand and will be available with lower costs and higher performance. From a regulatory point of view, the use of hydrogen as an energy resource has yet to be precisely defined, just as there is currently no standard available that quantifies the contribution of green hydrogen as a fuel in energy upgrading contexts (such as residential). Projects based on this technology have yet to be evaluated individually, which may act as a disincentive to its deployment.

Through the case study of a large residential building, it can be concluded that the current conditions are not convenient for the adoption of a fuel cell as an electrical generator in the manner discussed. The sensitivity analyses conducted show that the most influential factor is, without doubt, the cost of the raw material, which is currently still too expensive even assuming a stable and constant price reduction over the years. With a starting price of around 5 €/kg, the investment in upgrading the consumer's energy generation would be a slightly profitable investment and would contribute to heavily reducing pollutant emissions in the residential sector. The plants investigated will therefore be competitive with conventional technologies when the price of hydrogen falls and when it becomes available in the urban context.

Regarding the use of hydrogen in a mixture with natural gas and its use to fuel a boiler, there is no appreciable economic benefit in merely replacing the fuel, as long as it is not available at a lower price than conventional gas. A too low volumetric percentage of hydrogen in the mix also does not bring a drastic reduction in emissions, having hydrogen a much lower density than methane. Being present the current gas distribution network (considerably more widespread in Italy than in other countries), the blending of a small fraction of hydrogen into the network gas can be considered an easily implementable improvement in the current infrastructure and more positive from an overall point of view than it might affect the convenience of a consumer to equip itself with a boiler-type generator.

In the residential sector, the energy upgrading of buildings then represents an intangible value, difficult to quantify with an economic equivalence, but nevertheless of great value. The inclusion of hydrogen as a sustainable fuel recognised by the technical standards

on the energy certification of buildings would lead to an increase in the energy class of buildings that self-produce electrical and thermal energy through fuel cells.
The use of fuel cells for residential users of at least condominium size may be a solution of interest to energy communities, which may have ample space available to store hydrogen stores and may consider the possibility of distributing excess thermal energy produced when it is not consumed by the primary user. This would make it possible to exploit the maximum efficiency of fuel cells, which is generally very high, as well as decarbonise both electricity and heat supply with a single generation device.

In conclusion, it is believed that hydrogen represents a resource close to market competitiveness, a competitor to the redevelopment of the energy sector, and that its increased deployment can be of great benefit to both the consumers who use it and society as a whole.

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11 Bibliography

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